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Technology Assessment Report for Industrial Boiler Applications: Particulate Collection

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Technology Assessment Report for Industrial Boiler Applications: Particulate Collection

by

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ABSTRACT

The report assesses applicability of particulate control technology to industrial boilers. It is one of a series to aid in determining the technological basis for a New Source Performance Standard for Industrial Boilers. It gives current and potential capabilities of alternative particulate control techniques, and identifies the cost, energy, and environmental impacts of the most promising options. Fabric filters and electrostatic precipitators (ESPs) can exceed 99% control efficiency and can be used on industrial boilers. A baghouse seems more economical for very small combustion units or to meet a very stringent emissions requirement when burning low sulfur coal. An ESP might be more aptly applied to the largest industrial units, involving intermediate or moderate control levels for very small boilers and higher sulfur coals. Wet scrubbers are not expected to be used for particulate control alone, but might be used to control both SO2 and particulates in the case of modest particulate control levels. Mechanical collectors could be important for some cases. Control costs exert a significant impact as boiler size and control level decrease. For regulatory purposes, this assessment must be viewed as preliminary, pending relults of the more extensive examinations of impacts called for under Section III of the Clean Air Act.

PREFACE

The 1977 Amendments to the Clean Air Act required that emission standards be developed for fossil-fuel-fired steam generators. Accordingly, the U.S. Environmental Protection Agency (EPA) recently promulgated revisions to the 1971 new source performance standard (NSPS) for electric utility steam generating units. Further, EPA has undertaken a study of industrial boilers with the intent of proposing a NSPS for this category of sources. The study is being directed by EPA's Office of Air Quality Planning and Standards, and technical support is being provided by EPA's Office of Research and Development. As part of this support, the Industrial Environmental Research Laboratory at Research Triangle Park, N.C., prepared a series of technology assessment reports to aid in determining the technological basis for the NSPS for industrial boilers. This report is part of that series. The complete report series is listed below:

Title	Report No.
The Population and Characteristics of Industrial/ Commercial Boilers	EPA-600/7-79-178a
Technology Assessment Report for Industrial Boiler Applications: Oil Cleaning	EPA-600/7-79-178b
Technology Assessment Report for Industrial Boiler Applications: Coal Cleaning and Low Sulfur Coal	EPA-600/7-79-178c
Technology Assessment Report for Industrial Boiler Applications: Synthetic Fuels	EPA-600/7-79-178d
Technology Assessment Report for Industrial Boiler Applications: Fluidized-Bed Combustion	EPA-600/7-79-178e

Title	Report No.
Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modification	EPA-600/7-79-178f
Technology Assessment Report for Industrial Boiler Applications: NO_x Flue Gas Treatment	EPA-600/7-79-178g
Technology Asssessment Report for Industrial Boiler Applications: Particulate Collection	EPA-600/7-79-178h
Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization	EPA-600/7-79-178i

These reports will be integrated along with other information in the document, "Industrial Boilers - Background Information for Proposed Standards," which will be issued by the Office of Air Quality Planning and Standards.

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1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

This technology assessment report is intended to provide background information relative to particulate emissions control for fossil fuel-fired, industrial boilers used primarily for steam production.

Eight industrial-sized boilers have been chosen for evaluation such that a reasonable cross section of the industrial boiler population is represented.

Four types of control devices have been selected; i.e., electrostatic precipitators, fabric filters, multitube cyclones and wet scrubbers; to determine the potential economic, energy and environmental impacts for each particle collection system. These impacts must be addressed as delineated in the following excerpt from 40 CFR Part 52.21:

> "Best available control technology means an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."

Emission control levels for which these various impacts have been determined have been specified to allow assessment of the different control techniques at selected efficiency levels; the arbitrarily chosen values are as follows:

SIP (average state implementation plan level):

coal - 258 ng/J (0.6 $lb/10^6$ Btu)

oil - 43 ng/J (0.1 $lb/10^6$ Btu)

Moderate - 107.5 ng/J (0.25 $lb/10^6$ Btu)

Intermediate - 43 ng/J (0.1 $lb/10^6$ Btu)

Stringent - 12.9 ng/J (0.03 $lb/10^6$ Btu)

In the ensuing discussions of emission control technologies in various portions of this report, candidate technologies are compared using these three emission control levels. These control levels were chosen only to encompass all candidate technologies and form bases for comparison of technologies for control of specific pollutants considering performance, costs, energy, and non-air environmental effects.

From these comparisons, candidate "best" technologies for control of individual pollutants are recommended for consideration in any subsequent industrial boiler studies. These "best technology" recommendations do not consider combinations of technologies to remove more than one pollutant and have not undergone the detailed environmental, cost, and energy impact assessments necessary for regulatory action. Therefore, the levels of "moderate, intermediate, and stringent" and the recommendation of "best technology" for individual pollutants are not to be construed as indicative of the regulations that might be developed for industrial boilers. EPA will perform rigorous examination of several comprehensive regulatory options before any decisions are made regarding standards for emissions from industrial boilers.

The data presented in this report are directly applicable to the specific boiler types, sizes, fuels, operating conditions, control devices, and emission control levels presented herein. Caution should be exercised when extrapolating to sets of conditions not specified in this report.

The units selected for evaluation are listed in Table 1 while the detailed design and operating parameters and fuel analyses are given in Tables 2 through 9. In addition, steam production rates and boiler costs without controls are given in Table 10 for each of these units. Finally, Table 11 provides a comprehensive summary of capital, annualized, and operating costs for 60 appropriate boiler/fuel/control level/control device combinations.

1.2 SYSTEMS OF EMISSION REDUCTION FOR COAL-FIRED BOILERS

In terms of technological capabilities (Section 2.0), all of the control devices have been judged acceptable for each of the coal-fired units, although not at every control level. For example, electrostatic precipitators have been shown to be suitable at all control levels for each of the boilers whereas wet scrubbers and multitube cyclones can only be used where uncontrolled particle size distributions are high and/or required efficiencies are less than about 95 percent. Fabric filters would be suitable only at the stringent level. This information is summarized in Section 3.0, Table 31. In developing this table, the following factors have been taken into consideration: all control techniques including equipment reliability, the range of control efficiencies achievable based upon particle size by a given device, the costs of control, energy consumption as a function of control level and coal sulfur content, environmental impacts, potential adverse or beneficial impacts on boiler operation and maintenance, and compatibility with other pollutant control systems or multipollutant control capabilities.

Control equipment costs, Section 4.0, have been shown to be inversely proportional to emission control level, and, in the case of an electrostatic precipitator, also inversely proportional to coal sulfur content. Detailed cost estimates derived from vendor-supplied information indicate an average cost

TABLE 1. STANDARD BOILERS SELECTED FOR EVALUATION

Boiler type	Fuel	Thermal input MW (10^6 Btu/hr)
Field-erected, water-tube	Pulverized coal	117.2 (400)
Field-erected, water-tube	Pulverized coal	58.6 (200)
Field-erected, water-tube, spreader stoker	Coal	44.0 (150)
Field-erected, water-tube, chain grate stoker	Coal	22.0 (75)
Package, water-tube, underfeed stoker	Coal	8.8 (30)
Package, water-tube	Residual oil	44.0 (150)
Package, Scotch fire-tube	Distillate oil	4.4 (15)
Package, Scotch firetube	Natural gas	4.4 (15)

TABLE 2. DESIGN PARAMETERS FOR A FIELD-ERECTED, WATER-TUBE, PULVERIZED COAL-FIRED BOILER

Boiler configuration	Field erected, water-tube, pulverized coal			
Thermal input, MW (10^6 Btu/hr)	117.2 (400)	117.2 (400)	117.2 (400)	117.2 (400)
Fuel	Eastern high sulfur coal	Eastern medium sulfur coal	Eastern low sulfur coal	Subbituminous coal
Fuel rate, kg/sec (ton/hr)	4.27 (16.95)	3.82 (15.14)	3.65 (14.49)	5.25 (20.83)
Analysis (as received)				
% sulfur	3.5	2.3	0.9	0.6
% ash	10.6	13.2	6.9	5.4
Heating value, kJ/kg (Btu/lb)	27,447 (11,800)	30,733 (13,213)	32,099 (13,800)	22,330 (9,600)
Excess air, %	30	30	30	30
Flue gas flow rate, m^3/sec (acfm)	70.62 (149,639)	71.34 (151,153)	66.79 (141,528)	68.88 (145,950)
Flue gas temperature, °C (°F)	204° (400°)	204° (400°)	177° (350°)	177° (350°)
Load factor % (hr/yr)	60 (5,256)	60 (5,256)	60 (5,256)	60 (5,256)
Flue gas constituent, kg/hr (lb/hr)				
Fly ash	1,304.0 (2,874.72)	1,450.4 (3,197.57)	725.6 (1,599.70)	816.3 (1,799.71)
SO_2	1,022.6 (2,254.35)	600.2 (1,323.24)	224.8 (495.56)	215.4 (474.92)
NO_x	138.4 (305.1)	123.6 (272.52)	118.3 (260.82)	170.1 (374.94)
CO	7.7 (16.95)	6.9 (15.14)	6.6 (14.49)	9.4 (20.83)
Hydrocarbons as CH_4	2.3 (5.09)	2.1 (4.54)	2.0 (4.34)	2.8 (6.24)

TABLE 3. DESIGN PARAMETERS FOR A FIELD-ERECTED, WATER-TUBE, PULVERIZED COAL-FIRED BOILER

Boiler configuration	Field-erected, watertube, pulverized-coal					
Thermal input, MW (10^6 Btu/hr)	58.6	(200)	58.6	(200)	58.6	(200)
Fuel	Eastern high sulfur coal		Eastern low sulfur coal		Subbituminous coal	
Fuel rate, kg/sec (ton/hr)	2.13	(8.47)	1.83	(7.25)	2.63	(10.42)
Analysis (as received)						
% sulfur	3.5		0.9		0.6	
% ash	10.6		6.9		5.4	
Heating value, kJ/kg (Btu/lb)	27,447	(11,800)	32,099	(13,800)	22,330	(9,600)
Excess air, %	30		30		30	
Flue gas flow rate, m^3/sec (acfm)	35.30	(74,800)	33.32	(70,600)	34.55	(73,200)
Flue gas temperature, ^oC (^oF)	204	(400)	177	(350)	177	(350)
Load factor, % (hr/yr)	60	(5,256)	60	(5,256)	60	(5,256)
Flue gas constituent, kg/hr (lb/hr)						
Fly ash	650.74	(1436.51)	362.58	(800.40)	407.83	(900.29)
SO_2	510.31	(1126.51)	112.32	(247.95)	107.62	(237.58)
NO_x	69.06	(152.46)	59.12	(130.50)	84.96	(187.56)
CO	3.84	(8.47)	3.28	(7.25)	4.72	(10.42)
Hydrocarbons as CH_4	1.15	(2.54)	0.99	(2.18)	1.42	(3.13)

TABLE 4. DESIGN PARAMETERS FOR A FIELD-ERECTED, WATER-TUBE, SPREADER STOKER COAL-FIRED BOILER

Boiler configuration	Field-erected, watertube, spreader stoker					
Thermal input, MW (10^6 Btu/hr)	44.0	(150)	44.0	(150)	44.0	(150)
Fuel	Eastern high sulfur coal		Eastern low sulfur coal		Subbituminous coal	
Fuel rate, kg/sec (ton/hr)	1.60	(6.36)	1.37	(5.43)	1.97	(7.81)
Analysis (as received)						
% sulfur	3.5		0.9		0.6	
% ash	10.6		6.9		5.4	
Heating value, kJ/kg (Btu/lb)	27,447	(11,800)	32,099	(13,800)	22,330	(9,600)
Excess air, %	50		50		50	
Flue gas flow rate, m^3/sec (acfm)	30.58	(64,800)	28.69	(60,800)	29.64	(62,800)
Flue gas temperature, ^oC (^oF)	204	(400)	177	(350)	177	(350)
Load factor, % (hr/yr)	60	(5,256)	60	(5,256)	60	(5,256)
Flue gas constituent, kg/hr (lb/hr)						
Fly ash	397.01	(876.41)	220.64	(487.07)	248.36	(548.26)
SO_2	383.18	(845.88)	84.12	(185.71)	80.67	(178.07)
NO_x	43.22	(95.40)	36.90	(81.45)	53.07	(117.15)
CO	5.76	(12.72)	4.92	(10.86)	7.08	(15.62)
Hydrocarbons as CH_4	2.88	(6.36)	2.46	(5.43)	3.54	(7.81)

TABLE 5. DESIGN PARAMETERS FOR A FIELD-ERECTED, WATER-TUBE, CHAIN GRATE STOKER COAL-FIRED BOILER

Boiler configuration	Field-erected, watertube, chain grate					
Thermal input, MW (10^6 Btu/hr)	22.0	(75)	22.0	(75)	22.0	(75)
Fuel	Eastern high sulfur coal		Eastern low sulfur coal		Subbituminous coal	
Fuel rate, kg/sec (ton/hr)	0.80	(3.18)	0.69	(2.72)	0.99	(3.91)
Analysis (as received)						
% sulfur	3.5		0.9		0.6	
% ash	10.6		6.9		5.4	
Heating value, kJ/kg (Btu/lb)	27,447	(11,800)	32,099	(13,800)	22,330	(9,600)
Excess air, %	50		50		50	
Flue gas flow rate, m^3/sec (acfm)	15.24	(32,300)	14.21	(30,100)	14.82	(31,400)
Flue gas temperature, ^{o}C (^{o}F)	204	(400)	177	(350)	177	(350)
Load factor, % (hr/yr)	60	(5,256)	60	(5,256)	60	(5,256)
Flue gas constituent, kg/hr (lb/hr)						
Fly ash	76.35	(168.54)	42.51	(93.84)	47.82	(105.57)
SO_2	191.59	(422.94)	42.14	(93.02)	40.38	(89.15)
NO_x	21.61	(47.70)	18.48	(40.80)	26.57	(58.65)
CO	2.88	(6.36)	2.46	(5.44)	3.54	(7.82)
Hydrocarbons as CH_4	1.44	(3.18)	1.23	(2.72)	1.77	(3.91)

TABLE 6. DESIGN PARAMETERS FOR A PACKAGE, WATER-TUBE, UNDERFEED STOKER COAL-FIRED BOILER

Boiler configuration	Package, watertube, underfeed					
Thermal input, MW (10^6 Btu/hr)	8.8	(30)	8.8	(30)	8.8	(30)
Fuel	Eastern high sulfur coal		Eastern low sulfur coal		Subbituminous coal	
Fuel rate, kg/sec (ton/hr)	0.32	(1.27)	0.27	(1.09)	0.39	(1.56)
Analysis (as received)						
% sulfur	3.5		0.9		0.60	
% ash	10.60		6.90		5.40	
Heating value, kJ/kg (Btu/lb)	27,447	(11,800)	32,099	(13,800)	22,330	(9,600)
Excess air, %	50		50		50	
Flue gas flow rate, m^3/sec (acfm)	6.09	(12,900)	5.76	(12,200)	5.90	(12,500)
Flue gas temperature, ^{o}C (^{o}F)	204	(400)	177	(350)	177	(350)
Load factor, % (hr/yr)	60	(5,256)	60	(5,256)	60	(5,256)
Flue gas constituent, kg/hr (lb/hr)						
Fly ash	30.49	(67.31)	17.04	(37.61)	19.08	(42.12)
SO_2	76.52	(168.91)	16.89	(37.28)	16.13	(35.60)
NO_x	8.63	(19.05)	7.41	(16.35)	10.60	(23.40)
CO	1.15	(2.54)	0.99	(2.18)	1.41	(3.12)
Hydrocarbons as CH_4	0.58	(1.27)	0.49	(1.09)	0.71	(1.56)

TABLE 7. DESIGN PARAMETERS FOR A PACKAGE, WATER-TUBE, RESIDUAL OIL-FIRED BOILER

Boiler configuration	Package, watertube	
Thermal input, MW (10^6 Btu/hr)	44.0	(150)
Fuel	Residual fuel oil	
Fuel rate, m^3/hr (gal/hr)	3.79	(1,000)
Analysis		
% sulfur	3.0	
% ash	0.1	
Heating value, kJ/kg (Btu/gal)	43,043	(149,800)
Excess air, %	15	
Flue gas flow rate, m^3/sec (acfm)	22.04	(46,700)
Flue gas temperature, ^oC (^oF)	204	(400)
Load factor, % (hr/yr)	55	(4,818)
Flue gas constituents, kg/hr (lb/hr)		
Fly ash	14.95	(33.0)
SO_2	213.36	(471.0)
NO_x	27.18	(60.0)
CO	2.27	(5.0)
Hydrocarbons as CH_4	0.45	(1.0)

TABLE 8. DESIGN PARAMETERS FOR A PACKAGE, SCOTCH FIRE-TUBE, DISTILLATE OIL-FIRED BOILER

Boiler configuration	Package, Scotch firetube	
Thermal input, MW (10^6 Btu/hr)	4.4	(15)
Fuel	Distillate oil	
Fuel rate, m^3/hr (gal/hr)	0.41	(108)
Analysis		
% sulfur	0.5	
% ash	Trace	
Heating value, kJ/kg (Btu/gal)	45,346	(139,000)
Excess air, %	15	
Flue gas flow rate, m^3/sec (acfm)	2.36	(5,000)
Flue gas temperature, ^oC (^oF)	177	(350)
Load factor, % (hr/yr)	45	(3,942)
Flue gas constituent, kg/hr (lb/hr)		
Fly ash	0.10	(0.22)
SO_2	3.47	(7.67)
NO_x	1.08	(2.38)
CO	0.24	(0.54)
Hydrocarbons as CH_4	0.05	(0.11)

TABLE 9. DESIGN PARAMETERS FOR A PACKAGE, SCOTCH FIRE-TUBE, NATURAL GAS-FIRED BOILER

Boiler configuration	Package, Scotch firetube	
Thermal input, MW (10^6 Btu/hr)	4.4	(15)
Fuel	Natural gas	
Fuel rate, m^3/sec (ft^3/hr)	7.08	(15,000)
Analysis		
% sulfur	Trace	
% ash	Trace	
Heating value, MJ/m^3 (Btu/ft^3)	373	(1,000)
Excess air, %	15	
Flue gas flow rate, m^3/sec (acfm)	2.45	(5,200)
Flue gas temperature, ^oC (^oF)	177	(350)
Load factor, % (hr/yr)	45	(3,942)
Flue gas constituent, kg/hr (lb/hr)		
Fly ash	0.07	(0.15)
SO_2	0.005	(0.01)
NO_x	1.19	(2.63)
CO	0.12	(0.26)
Hydrocarbons as CH_4	0.02	(0.05)

TABLE 10. ANNUALIZED COSTS AND STEAM CHARACTERISTICS FOR EIGHT "STANDARD" BOILERS (UNCONTROLLED)

Boiler type heat input, MW (10^6 Btu/hr) and fuel type	Steam conditions kPa/°C (psig/°F)	Steam enthalpy kJ/kg (Btu/lb)	Steam production rate* kg/hr (lb/hr)	Total annualized cost of uncontrolled boiler ($)	Steam cost based upon steam output $/$10^3$ kg ($/$10^3$ lb)	Steam cost based upon net thermal output of steam $/$10^3$ J ($/$10^6$ Btu)
Pulverized Coal						
117.2						
(400)						
Eastern high sulfur				7,783,600	11.60 (5.26)	4.13 (4.36)
Eastern medium sulfur	5171/399	3195	127,772	7,840,700	11.68 (5.30)	4.16 (4.39)
Eastern low sulfur	(750/750)	(1375)	(281,690)	8,109,500	12.08 (5.48)	4.30 (4.54)
Subbituminous				7,930,000	11.82 (5.36)	4.21 (4.44)
58.6						
(200)						
Eastern high sulfur				4,247,700	12.65 (5.74)	4.50 (4.75)
Eastern medium sulfur	5171/399	3195	63,887	NA	- -	- -
Eastern low sulfur	(750/750)	(1375)	(140,845)	4,380,000	13.05 (5.92)	4.65 (4.90)
Subbituminous				4,368,600	13.01 (5.90)	4.64 (4.89)
Spreader Stoker						
44.0						
(150)						
Eastern high sulfur				3,075,000	11.46 (5.20)	4.35 (4.59)
Eastern medium sulfur	3103/316	3025	51,000	NA	- -	- -
Eastern low sulfur	(450/600)	(1302)	(112,434)	3,186,300	11.88 (5.39)	4.50 (4.75)
Subbituminous				3,121,100	11.64 (5.28)	4.42 (4.66)
Chain Grate Stoker						
22.0						
(75)						
Eastern high sulfur				1,851,200	12.52 (5.68)	5.23 (5.52)
Eastern medium sulfur	1034/186	2779	28,129	1,861,500	12.59 (5.71)	5.27 (5.56)
Eastern low sulfur	(150/366)	(1196)	(62,014)	1,893,900	12.81 (5.81)	5.36 (5.65)
Subbituminous				1,865,800	12.61 (5.72)	5.28 (5.57)

(continued)

TABLE 10 (continued)

Boiler type heat input, MW (10^6 Btu/hr) and fuel type	Steam conditions kPa/°C (psig/°F)	Steam enthalpy kJ/hr (Btu/lb)	Steam production rate* kg/hr (lb/hr)	Total annualized cost of uncontrolled boiler ($)	Steam cost based upon steam output		Steam cost based upon net thermal output of steam	
					$/10^3 kg	($/10^3 lb)	$/10^3 J	($/10^6 Btu)
Underfeed Stoker								
8.8								
(30)								
Eastern high sulfur				952,300	16.09	(7.30)	6.74	(7.11)
Eastern medium sulfur	1034/186	2779	11,251	NA	-	-	-	-
Eastern low sulfur	(150/366)	(1196)	(24,805)	957,900	16.20	(7.35)	6.78	(7.15)
Subbituminous				976,900	16.51	(7.49)	6.91	(7.29)
Residual Oil								
44.0								
(150)	5171/399	3195	47,915	2,527,200	10.96	(4.97)	3.90	(4.11)
3.0% S	(750/750)	(1375)	(105,634)					
Distillate Oil								
4.4								
(15)	1034/186	2779	5,626	558,600	25.20	(11.43)	10.53	(11.11)
0.5% S	(150/366)	(1196)	(12,403)					
Natural Gas								
4.4								
(15)	1034/186	2779	5,626	496,000	22.35	(10.14)	9.36	(9.87)
trace sulfur	(150/366)	(1196)	(12,403)					

*Steam production rate calculated by assuming a boiler efficiency of 85 percent and a feedwater enthalpy of 390 kJ/kg (168 Btu/lb) at 93°C (200°F).

NA = Not available.

TABLE 11. SUMMARY COST AND OPERATING DATA FOR PARTICULATE CONTROL EQUIPMENT

Boiler type heat input MW (10^6 Btu/hr) Fuel		Flow rate		Control level*	Control efficiency (%)	Control device†	Capital investment			Annualized cost‡			Annual operating cost			Energy consumption§		Solid waste	
% S	% Ash	m^3/hr	(acfm)				$	$/$m^3$/hr	($/acfm)	$	$/$10^3$ kg	($/ton)	$	$/$m^3$/hr	($/acfm)	kW	% of heat input	g/sec	(lb/hr)
A. Pulverized Coal																			
58.6	(200)																		
3.5	10.6	1.27×10^5	(74,800)	S	99.58	FF	986,823	7.77	13.19	330,223	96.64	87.85	177,796	1.40	2.38	95.4	0.164	180	1430
				S	99.58	ESP	767,280	6.04	10.26	279,168	81.70	74.27	162,589	1.28	2.17	31.7	0.055	180	1430
				I	98.61	ESP	680,647	5.36	9.10	262,690	77.61	70.56	159,807	1.26	2.14	26.4	0.044	179	1417
				SIP	91.64	ESP	435,238	3.43	5.82	210,718	67.01	60.92	146,415	1.15	1.96	18.4	0.031	166	1316
0.9	6.9	1.2×10^5	(70,600)	S	99.25	FF	969,927	8.09	13.74	262,638	138.42	125.84	110,211	0.92	1.56	90.2	0.154	100	794
				S	99.25	ESP	1,231,840	10.27	17.45	301,103	158.71	144.28	108,323	0.90	1.53	99.3	0.171	100	794
				I	97.50	ESP	1,183,172	9.86	16.76	288,719	154.92	140.84	103,503	0.86	1.47	77.2	0.133	98	780
				SIP	85.0	ESP	870,061	7.25	12.32	222,345	136.79	124.35	86,347	0.72	1.22	44.4	0.075	86	680
0.6	5.4	1.24×10^5	(73,200)	S	99.33	FF	972,658	7.82	13.29	273,564	128.05	116.41	121,137	0.98	1.65	93.2	0.160	113	894
				S	99.33	ESP	1,279,726	10.29	17.48	322,358	150.89	137.17	122,511	0.99	1.67	124.0	0.212	113	894
				I	97.78	ESP	1,190,957	9.58	16.27	302,604	143.91	130.83	116,672	0.94	1.59	96.5	0.165	111	880
				SIP	86.67	ESP	1,032,921	8.30	14.11	260,991	139.98	127.25	99,564	0.80	1.36	55.8	0.096	98	780
B. Spreader Stoker																			
44	(150)																		
3.5	10.6	1.1×10^5	(64,800)	S	99.5	FF	794,508	7.22	12.26	239,292	114.90	104.45	115,230	1.05	1.78	82.6	0.188	110	872
				S	99.5	ESP	665,558	6.04	10.27	205,330	98.58	89.62	102,562	0.93	1.58	26.7	0.061	110	872
				I	98.3	ESP	553,094	5.03	8.54	184,982	102.86	93.51	100,038	0.91	1.54	22.0	0.051	109	861
				I	98.3	FDS	572,648	5.20	8.84	278,644	135.39	123.08	162,239	1.47	2.50	231.2	0.525	109	861
				M	95.72	MC	100,369	0.91	1.55	26,717	-	-	11,255	0.10	0.17	82.6	0.188	106	839
				SIP	89.73	ESP	345,427	3.14	5.33	141,961	75.58	68.71	89,703	0.82	1.38	15.1	0.034	99	786
0.9	6.9	1.03×10^5	(60,800)	S	99.1	FF	784,108	7.59	12.90	197,694	171.50	155.91	73,632	0.71	1.21	77.6	0.177	61	483
				S	99.1	ESP	1,154,789	11.18	18.99	254,706	220.96	200.87	72,779	0.71	1.20	82.4	0.187	61	483
				I	96.92	ESP	1,062,224	10.28	17.47	235,782	232.07	210.98	68,435	0.66	1.13	63.2	0.143	60	472
				I	96.92	FDS	562,418	5.44	9.25	237,724	210.72	191.56	121,319	1.18	2.00	151.7	0.344	60	472
				M	92.31	MC	100,199	0.97	1.65	26,039	-	-	10,577	0.10	0.17	77.6	0.177	57	450
				SIP	81.54	ESP	705,365	6.83	11.60	165,260	174.13	158.30	54,223	0.53	0.89	35.3	0.082	50	397
0.6	5.4	1.07×10^5	(62,800)	S	99.18	FF	785,803	7.36	12.51	204,473	157.40	143.09	80,411	0.75	1.28	80.1	0.181	69	544
				S	99.18	ESP	1,163,651	10.91	18.53	264,911	203.92	185.38	81,937	0.77	1.30	102.1	0.232	69	544
				I	97.27	ESP	1,135,079	10.64	18.07	256,071	221.55	201.41	77,473	0.73	1.23	78.6	0.177	67	533
				I	97.27	FDS	564,028	5.29	8.98	244,164	191.57	174.15	127,759	1.20	2.03	224.0	0.508	67	533
				M	93.17	MC	100,267	0.94	1.60	26,310	-	-	10,848	0.10	0.17	80.1	0.181	64	511
				SIP	83.61	ESP	881,421	8.26	14.04	201,827	184.24	167.49	63,083	0.59	1.00	43.9	0.099	58	458

(continued)

TABLE 11 (continued)

Boiler type heat input MW (10^6 Btu/hr) Fuel % S	% Ash	Flow rate m^3/hr	(acfm)	Control level*	Control efficiency (%)	Control device†	Capital investment $	$/m^3/hr	($/acfm)	Annualized cost‡ $	$/10^3 kg	($/ton)	Annual operating cost $	$/m^3/hr	($/acfm)	Energy consumption§ kW	% of heat input	Solid waste g/sec	(lb/hr)
55	(188)																		
0.8	7.5	1.48×10^5	(87,100)	S	99.7	FF	580,908	3.93	6.67	244,277	143.16	130.14	141,282	0.95	1.62	138.7	0.252	90	714
45	(154)																		
0.8	7.5	1.41×10^5	(83,100)	I	97.3	ESP	733,114	5.19	8.82	212,202	155.41	141.28	88,282	0.63	1.06	141.7	0.315	72	572
C. Chain Grate Stoker																			
22	(75)																		
3.5	10.6	5.49×10^4	(32,300)	S	98.67	ESP	306,731	5.59	9.50	72,586	182.71	166.10	23,854	0.43	0.74	11.2	0.051	21	167
				S	98.67	IWS	1,000,061	18.22	30.96	285,314	718.18	652.89	75,460	1.37	2.34	115.0	0.522	21	167
				I	95.56	IWS	485,179	8.84	15.02	152,222	395.85	359.86	49,788	0.91	1.54	115.0	0.522	20	162
				SIP	73.33	ESP	105,026	1.91	3.25	34,034	115.19	104.72	17,185	0.31	0.53	5.7	0.027	16	124
0.9	6.9	5.1×10^4	(30,100)	S	97.6	ESP	723,868	14.16	24.05	137,242	626.42	569.47	21,956	0.43	0.73	32.8	0.150	12	92
				S	97.6	IWS	998,040	19.52	33.16	277,229	1,265.36	1,150.33	67,375	1.32	2.24	107.2	0.488	12	92
				I	92.0	IWS	483,189	9.45	16.05	144,260	699.06	635.51	41,826	0.82	1.39	75.2	0.341	11	87
				SIP	52.0	ESP	183,897	3.60	6.11	40,169	345.20	313.82	10,483	0.21	0.35	10.1	0.044	6	49
0.6	5.4	5.34×10^4	(31,400)	S	97.87	ESP	831,551	15.59	26.48	157,352	638.69	580.63	25,026	0.47	0.80	40.9	0.188	13	104
				S	97.87	IWS	998,374	18.72	31.80	278,565	1,130.71	1,027.92	68,711	1.29	2.19	111.8	0.508	13	104
				I	92.91	IWS	483,506	9.06	15.40	145,528	622.89	566.26	43,094	0.81	1.37	78.4	0.358	12	99
				SIP	57.45	ESP	262,924	4.93	8.37	54,835	379.36	344.87	12,641	0.24	0.40	12.7	0.058	8	61
40	(137)																		
0.8	7.5			M	97.0	MC	226,080	1.81	3.08	195,060	58.16	52.88	163,376	1.31	2.23	98.5	0.246	177	1404
D. Underfeed Stoker																			
8.8	(30)																		
3.5	10.6	2.2×10^4	(12,900)	S	98.66	FF	242,571	11.07	18.80	57,948	364.24	331.13	17,923	0.81	1.39	16.4	0.188	8	66
				S	98.66	ESP	131,435	6.00	10.19	32,501	204.29	185.72	11,197	0.51	0.87	4.3	0.048	8	66
				I	95.54	ESP	96,517	4.40	7.48	26,360	239.95	218.14	10,598	0.48	0.82	3.5	0.041	8	64
				M	88.84	MC	51,745	2.36	4.01	10,506	-	-	2,404	0.11	0.19	16.4	0.188	7.5	60
				SIP	73.21	ESP	44,906	2.05	3.48	16,113	136.35	123.95	8,492	0.39	0.66	2.2	0.024	6	49
0.9	6.9	2.07×10^4	(12,200)	S	97.6	FF	241,764	11.67	19.82	54,719	620.52	564.11	14,694	0.71	1.20	15.6	0.177	5	37
				S	97.6	ESP	348,001	16.79	28.52	66,653	755.85	687.14	10,820	0.52	0.89	13.0	0.147	5	37
				I	92.0	ESP	242,085	11.68	19.84	48,329	709.87	645.34	9,316	0.45	0.76	9.3	0.106	4	35
				M	80.0	MC	51,718	2.50	4.24	10,397	-	-	2,295	0.11	0.19	15.6	0.177	4	30
				SIP	52.0	ESP	78,532	3.79	6.44	18,910	407.86	370.78	5,824	0.28	0.48	4.0	0.044	2.5	20

(continued)

TABLE 11 (continued)

Boiler type heat input MW (10^6 Btu/hr) Fuel % S	% Ash	Flow rate m^3/hr	(acfm)	Control level*	Control efficiency (%)	Control device†	Capital investment $	$/$m^3$/hr	($/acfm)	Annualized cost‡ $	$/$10^3$ kg	($/ton)	Annual operating cost $	$/$m^3$/hr	($/acfm)	Energy consumption§ kW	% of heat input	Solid waste g/sec	(lb/hr)
0.6	5.4	2.12×10^4	(12,500)	S	97.86	FF	241,897	11.39	19.35	55,254	557.61	506.92	15,229	0.72	1.22	16.0	0.181	5	41
				S	97.86	ESP	416,736	19.62	33.34	78,934	796.59	724.17	12,200	0.58	0.98	16.0	0.181	5	41
				I	92.86	ESP	287,985	13.56	23.04	56,695	717.10	651.91	10,410	0.49	0.83	11.4	0.130	5	39
				M	82.14	MC	51,732	2.44	4.14	10,452	-	-	2,350	0.11	0.19	16.0	0.181	4	35
				SIP	57.14	ESP	107,170	5.04	8.57	24,263	423.64	385.13	6,645	0.31	0.53	5.0	0.058	3	24

* S = Stringent
I = Intermediate
M = Moderate
SIP - State Implementation Plan

† ESP = Electrostatic Precipitator
FF = Fabric Filter
MC = Mechanical Collector
FDS = Flooded Disc Scrubber
IWS = Ionizing Wet Scrubber

‡ Unit costs are equal to cost-effectiveness for each example.

§ Energy consumption of particulate control device only.

impact (increase) of about 5 percent over uncontrolled, annualized boiler cost data.

Energy penalties associated with operation and maintenance of control equipment are shown in Section 5.0 to be lowest for precipitators when 3.5 percent sulfur coal is burned followed by multitube cyclones, fabric filters, and scrubbers. Fabric filter power requirements are essentially insensitive to coal sulfur content (although unusually high acidity levels may damage some fabrics) and emission control level while electrostatic precipitator energy requirements exceed those for fabric filters at the low sulfur - low emission level combination. The increased electrical consumption of an electrostatic precipitator at these low sulfur levels is primarily due to decreased particle migration velocities which necessitate increased plate area and correspondingly higher energy inputs for electrification, rapping, and gas handling. Scrubbers are shown to be very energy-intensive, especially for the capture of fine particles.

Environmentally-related impacts of particulate reduction are judged in Section 6.0 to be generally beneficial. This is based on the potential ramifications of decreased stack emissions versus increased solid waste disposal. In addition, environmental impacts resulting from utility-supplied energy requirements should also be small since these (utility) units will be well-controlled. The potentially adverse impacts of increased solid waste disposal can be minimized even further with the advent of new and stricter disposal regulations and increased fly ash utilization in such areas as road construction, brick manufacturing, and concrete production.

The performance data presented in Sections 2.0 and 7.0 show particulate control systems to be well advanced, commercially available, and generally reliable if properly operated and maintained. However, as the emission control level becomes stricter, costs and reliability must be carefully scrutinized. Because of variations in boiler operation, occasional stack emissions in excess of any emission control level may occur over long periods of operation. The probability of this happening increases as the control level becomes more stringent. Opacity considerations are addressed in general only as a more in-depth analysis of opacity versus mass emissions is presently ongoing at GCA/Technology Division, with a report to be published in early 1980.

1.3 SYSTEMS OF EMISSION REDUCTION FOR OIL-FIRED BOILERS

The electrostatic precipitator appears to be the only practical control device for reduction of particulate emissions from residual oil-fired facilities. Multitube cyclones or wet scrubbers could also be used, but only at modest emission control levels. For distillate oil-fired units, controls will be unnecessary for boilers that are properly operated and maintained because of the low levels of uncontrolled emissions.

The costs of particulate emissions control are lower for residual oil systems than for coal-fired plants, but much less cost-effective based on annualized dollars per unit of pollutant removed per year. This is due to the lower uncontrolled dust loadings for the residual oil-fired boiler as compared to the coal-fired units, and the higher proportion of fine-sized, lightweight fly ash emitted by the oil-fired units.

1.4 SYSTEMS OF EMISSION REDUCTION FOR GAS-FIRED BOILERS

Gas-fired boilers fall into the same category as distillate-fired units; uncontrolled emission rates are very low and with proper operation and maintenance of equipment will not require particulate controls.

2.0 EMISSION CONTROL TECHNIQUES

2.1 PRINCIPLES OF CONTROL

In this section, the control options available to industrial boiler facilities firing coal, residual and distillate oil, natural gas and those capable of firing multiple fuels will be delineated. Four control techniques will be considered; electrostatic precipitation, fabric filtration, wet scrubbing, and mechanical collection.

In order to properly assess the capability of each control technique, uncontrolled emissions from each of the boiler types considered must first be examined. Uncontrolled emission levels are given in emission factor documents (AP-42), calculable from mass balances, and as field performance data. Representative information is presented in Table 12.

Particle size parameters for these uncontrolled emissions are also necessary for an accurate appraisal of the capabilities of the various control alternatives considered. Table 13 shows the expected ranges in particle sizes for uncontrolled emissions from various boilers. Generally, stoker boilers emit the coarsest material, while oil- and natural gas-fired systems discharge predominantly fine material, $< 2\mu$. The sizes reported in Table 13 are the mass median diameters.

TABLE 12. UNCONTROLLED PARTICULATE EMISSIONS FROM "STANDARD" INDUSTRIAL BOILERS

Boiler type	Boiler data: Heat input MW (10^6 Btu/hr)	Boiler data: Firing rate*	Fuel: % S	Fuel: % ash	Fuel: HHV†	Uncontrolled emissions ng/J (lb/10^6 Btu): AP-42‡	Uncontrolled emissions ng/J (lb/10^6 Btu): Test data	Uncontrolled emissions ng/J (lb/10^6 Btu): PEDCo standard boiler data§
A. Coal - pulverized dry bottom	117.2 (400)	4.27 (16.95)	3.5	10.6	27,447 (11,800)	3,281 (7.63)		3,092 (7.19)
		3.82 (15.14)	2.3	13.2	30,733 (13,213)	3,651 (8.49)		3,436 (7.99)
		3.65 (14.49)	0.9	6.9	32,099 (13,800)	1,827 (4.25)		1,720 (4.00)
		5.25 (20.73)	0.6	5.4	22,330 (9,600)	2,055 (4.78)		1,935 (4.50)
	58.6 (200)	2.13 (8.47)	3.5	10.6	27,447 (11,800)	3,281 (7.63)		3,087 (7.18)
		1.83 (7.25)	0.9	6.9	32,100 (13,800	1,827 (4.25)		1,720 (4.00)
		2.63 (10.42)	0.6	5.4	22,330 (9,600)	2,055 (4.78)		1,935 (4.50)
B. Coal - spreader stoker	44.0 (150)	1.60 (6.36)	3.5	10.6	27,447 (11,800)	2,511 (5.84)		2,511 (5.84)
		1.37 (5.43)	0.9	6.9	32,100 (13,800)	1,397 (3.25)		1,397 (3.25)
		1.97 (7.81)	0.6	5.4	22,330 (9,600)	1,574 (3.66)		1,574 (3.66)
C. Coal - chain grate stoker	22.0 (75)	0.8 (3.18)	3.5	10.6	27,447 (11,800)	967.5 (2.25)		967.5 (2.25)
		0.69 (2.72)	0.9	6.9	32,100 (13,800)	537.5 (1.25)		537.5 (1.25)
		0.99 (3.91)	0.6	5.4	22,300 (9,600)	606.3 (1.41)		606.3 (1.41)
D. Coal - underfeed stoker	8.8 (30)	0.32 (1.27)	3.5	10.6	27,447 (11,800)	387 (0.90)		963.2 (2.24)
		0.27 (1.09)	0.9	6.9	32,100 (13,800)	215 (0.50)		537.5 (1.25)
		0.39 (1.56)	0.6	5.4	22,330 (9,600)	241 (0.56)		602 (1.40)
E. Residual oil	44.0 (150)	3.8 (1000)	3.0	0.1	43,043 (149,800)	94.6 (0.22)	16.6-154.6 (0.0385-0.3596)[1]	
F. Distillate oil	4.4 (15)	0.41 (108)	0.5	-	45,346 (139,000)	6.19 (0.0144)	3.74-14.6 (0.0087-0.0339)[1]	6.45 (0.015)
G. Natural gas	4.4 (15)	7.08 (15,000)	-	-	373 (1000)	2.15-6.45 (0.005-0.015)	0.34-5.11 (0.0008-0.0119)[1]	4.3 (0.01)

*Coal - kg/s (ton/hr)
Oil - m^3/hr (gal/hr)
Gas - m^3/sec (ft^3/hr)

†HHV - high heating value:
Coal - kJ/kg (Btu/lb)
Oil - kJ/kg (Btu/gal)
Gas - MJ/m^3 (Btu/ft^3

‡EPA Publication AP-42 — "Compilation of Air Pollutant Emission Factors." Given as follows (A and S are percent by weight of ash and sulfur respectively):

A. 17A lbs particulate per ton coal burned.
B. 13A lbs particulate per ton coal burned.
C. 5A lbs particulate per ton coal burned.
D. 2A lbs particulate per ton coal burned.
E. 10(S) + 3 lbs particulate per 1000 gallons burned.
F. 2 lbs particulate per 1000 gallons burned.
G. 5 to 15 lbs particulate per 10^6 ft^3 burned.

§See Tables 2 through 9 for uncontrolled emission data.

TABLE 13. PARTICLE SIZE DATA (μm) ASSOCIATED WITH SEVEN "STANDARD" FIRING METHODS (UNCONTROLLED)

	Particle size - mass median diameter - (μm)			
	Reference 2	Reference 3	Reference 4	Reference 5
A. Coal - pulverized	10	20	20	-
B. Coal - spreader stoker	-	70	48	-
C. Coal - chain grate stoker	-	100	75	-
D. Coal - underfeed stoker	-	-	16	-
E. Residual oil	2.5	-	90% < 2μ	1.2
F. Distillate oil	5.0	-	90% < 2μ	-
G. Natural gas	-	-	90% < 2μ	-

2.2 CONTROLS FOR COAL-FIRED BOILERS

2.2.1 Electrostatic Precipitation

2.2.1.1 System Description--

The basic collection processes taking place in an electrostatic precipitator (ESP) are as follows: (1) suspended particles are given an electrical charge; (2) the charged particles then migrate to a collecting electrode of opposite polarity while subjected to a diverging electric field; and (3) the collected material is then dislodged from the collection electrodes.

Electric charging of the particles is usually caused by ions produced in the high voltage d-c corona. Removal of the collected material is accomplished by rapping or vibrating the electrodes.

A typical cross section of an ESP is shown in Figure 1.[6]

Some of the key components and subsystems associated with an ESP unit are: (1) the collecting and discharge electrodes; (2) high voltage transformers and rectifiers; (3) electrode rappers; (4) gas distributors (guide vanes); and (5) structural features such as the shell, manifolds, hoppers and ducting. A brief discussion of each is given in the following paragraphs.[7]

Most discharge electrodes in the U.S.A. appear as smooth wires of about 0.254 cm (0.1 inch) diameter that are held in a fixed position by weights suspended from the lower ends. These wires are usually protected from burning, which ultimately leads to breaking, by electrostatic shrouds at the tops and bottoms of the wires. Collecting plates often consist of solid-sheet with structural stiffeners although special contours; e.g., corrugated, may be incorporated in some designs to improve gas flow distribution and facilitate cleaning.

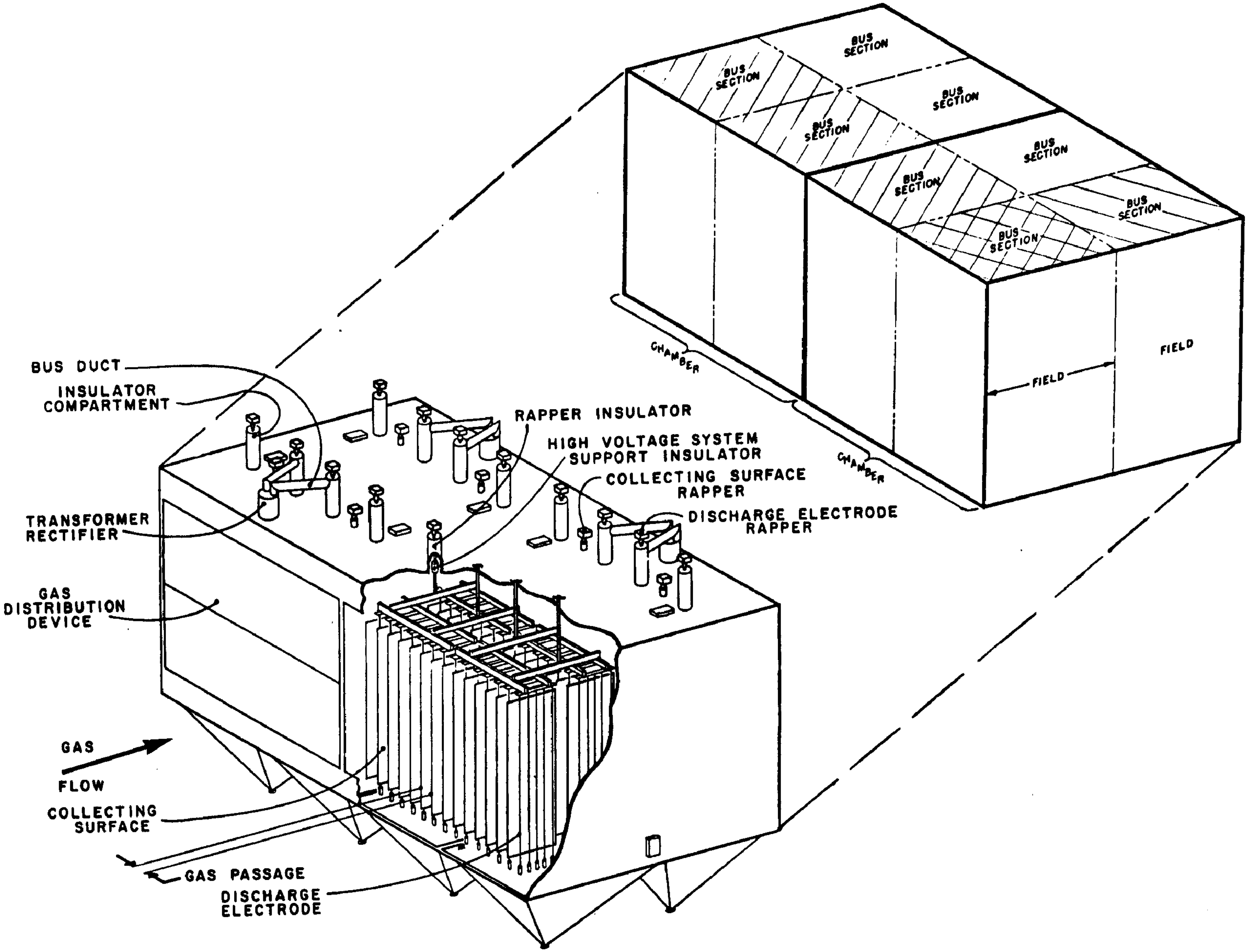

Figure 1. Typical precipitator cross section.[6]

The high voltage equipment used in the ESP serves the dual role of providing intense electric fields and the corona currents necessary for particle charging. Automatic control of rectifier output is usually required for boiler applications because of varying electrical loads and fuel conditions.

Perhaps the most difficult task encountered in applying electrostatic precipitators is that of removing the dust deposits from the collection plates while minimizing their reentrainment in the outlet gas stream. Ideally, a sharp rap of a collecting electrode at the proper intensity should accelerate the dust mass sufficiently to break the adhesive bonds at the dust/plate interface. When the thickness and composition of the dust layer permit a uniform dislodgement, fly ash can be very effectively removed. Observations on some units have revealed a complete detachment of platelike dust layers or sheets that fall into the collection hopper below. Under the above circumstances, the redispersion and resuspension of fine particles in the gas stream is usually minimized unless the dust level is too high in the hoppers. In general practice, however, both deposition and dislodgement patterns are nonuniform such that optimum particle capture is not achieved and dust reentrainment may account for an appreciable fraction of the total emission.

Deliberate interruption of power to a plate section undergoing cleaning may increase the dust removal via reduced adhesion. Lowered gas velocities, with no decrease in plate area, aid in reducing reentrainment. Although the resultant increase in SCA favors increased collection, the physical plant can no longer accommodate the required gas flow rate. Electrode rapping or vibrating with its attendant reentrainment potential cannot be avoided unless a flush-down, wet plate system is used. However, by sectionalizing the system in multiple series - parallel arrays - there will always be an electrical backup except when the most downstream plate sections are rapped.

Good gas flow distribution is a function of the form of the interconnecting breeching between the boiler and the precipitator but most ESP's employ guide vanes to prevent flow separation at elbows and diffusion screens to reduce turbulence at the collector entrance. Improvement in gas flow uniformity can result in greatly increased efficiency. For new installations, the use of models at 1:16 or 1:8 scale for flow analysis is routine practice.

Structural features of an ESP are important insofar as maintaining electrode alignment and configuration. They are especially important in "hot" precipitators (those installed upstream of the air heater) because of the potential for distortion caused by large thermal stresses. Complete insulation of shell, hoppers, and connecting duct work is required to prevent corrosion due to condensation of moisture and acid and also to minimize stresses due to temperature differences.

Since electrostatic precipitation is a well-established technology, there is usually no problem with respect to commercial availability. The time required to establish specifications, design, fabricate, ship, and erect an ESP unit for a utility boiler is on the order of 2 to 4 years, depending on site-specific factors and vendor workload.[8] It is conceivable that a shorter period could be realized for smaller-sized industrial plants.

Electrostatic precipitation technology dates back to the early 1900's when the first successful application was made by Cottrell in 1907 for collection of acid mist at a sulfuric acid plant. The first power boiler application was in 1923 at Detroit Edison's Trenton Channel Plant.[9] This installation consisted of three units handling a total gas flow of 1.36×10^6 m^3/hr (800,000 acfm), designed for a collection efficiency of 90 percent. Several years were required before the many operational problems encountered were solved.

Limited data are available with respect to the number of ESP systems sold over the last several years for control in the boiler industry. In terms of millions of dollars, ESP sales in the United States were as follows for the 1972 to 1975 period:[10]

1972	1973	1974	1975
86.2	167.5	326.2	226.8

The 1978 precipitator market for the United States is projected to be around $400 million.

Data for power boilers indicate that shipments were expected to decline in 1977 to $1,020 million with a capacity of 89 million kg (197 million pounds) of steam per hour as compared with $1,140 million in 1976 with capacity of 99 million kg (218 million pounds) of steam.[11]

The applicability of ESP technology to the coal-fired boilers being studied in this document presents no problems with respect to the boiler firing methods and their respective sizes from an engineering standpoint. Generally, ESP modules can be furnished in sizes down to about 8500 m^3/hr (5000 acfm). With respect to fuel characteristics, there are several factors which may adversely affect ESP performance, such as the sulfur or alkali metal content of the coal being fired. These problems are discussed in greater detail subsequently.

Some of the more important design criteria to be considered in the selection and utilization of electrostatic precipitators are given in Table 14.[12] Additionally, some basic parameters used in precipitator design as well as

TABLE 14. CRITICAL PARAMETERS FOR ELECTROSTATIC PRECIPITATOR OPERATION[12]

A. <u>Design</u>

1. Collection plates

   Specific area
   Aspect ratio
   Plate area/rapper
   Plate area/transformer set
   Number of plate sections
   - Series connected
   - In parallel

2. Corona electrodes

   Number/section
   - Series and parallel connected

   Length/rapper
   Alignment stability
   Insulation methods
   - Heating, shielding, gas flush

   Corona power density (W/ft^2)
   Corona power (W/cfm)
   Corona electrode tensioning

3. Electrical system

   Average field strength
   Wave form
   Automatic voltage control

4. Cleaning procedures

   Number rappers/unit plate area
   Method, location and intensity of rapping
   Dust level in hoppers
   Dust removal from hoppers

B. <u>Operating Parameters</u>

   Gas flow rate/linear velocity/residence time
   Gas temperature in ESP
   Use of flue gas conditioners
   Gas flow distributors
   Cleaning (rapping) frequency

C. <u>Aerosol Properties</u>

   Gas temperature and moisture content
   Dust concentration and size properties
   Fly ash components
   Sulfur, alkaline oxides
   Catalytic agents (Fe_2O_3)
   Trace metals

typical numerical values used for fly ash systems are given in Table 15.[13] The variations in design parameters, which are commonplace, are attributable to broad differences in fly ash properties encountered in the field, different efficiency requirements, and conservatism in design practice.

The three most important design criteria are the precipitation rate (W_e), the specific collection area (SCA), and the gas velocity, V. Because precipitation rate can vary with resistivity, particle size distribution, gas velocity distribution, rapping, and electrical factors, an effective rate parameter or migration velocity is usually adopted. Variation of this parameter with fly ash resistivity and coal sulfur content is shown in Figures 2 and 3.[14]

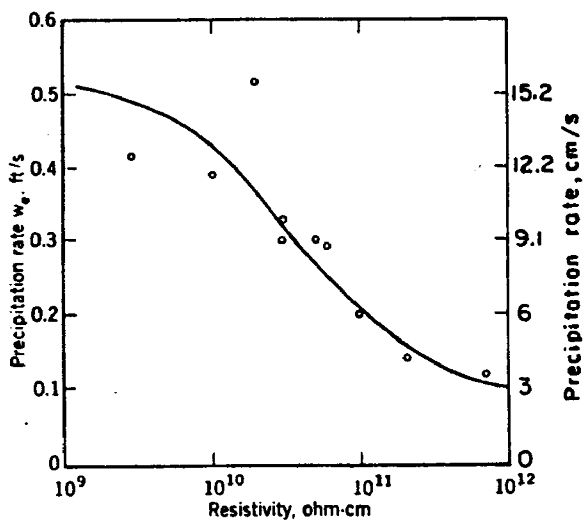

Figure 2. Drop in precipitation rate W_e with increasing fly ash resistivity for a representative group of precipitators.[14]

TABLE 15. RANGE OF BASIC DESIGN PARAMETERS FOUND IN THE FIELD FOR FLY ASH PRECIPITATORS[13]

Parameter	Symbol	Range of values
Duct spacing	s	20.3 to 30.5 cm (8 to 12 in.)
Precipitation rate	W_e	0.015 to 0.183 m/s (0.05 to 0.60 ft/s)
Specific collector area	SCA or $\frac{A}{V}$	328 to 2630 m^2/1000 m^3/min (100 to 800 ft^2/1000 cfm)
Gas velocity	V	1.2 to 2.4 m/s (4 to 8 ft/s)
Aspect ratio (plate length/plate height)	$\frac{L}{H}$	0.5 to 1.5 (dimensionless)
Corona power	$\frac{Pc}{V}$	1770 to 17,700 watts/1000 m^3/min (50 to 500 watts/1000 cfm)
$\frac{\text{Corona current}}{\text{plate area}}$	$\frac{Ic}{A}$	54 to 753 μamps/m^2 (5 to 70 μamps/ft^2)
Plate area per electrical set	A_s	465 to 7430 m^2/el. set (5000 to 80,000 ft^2/el. set)
Number of high tension sections in gas flow direction	N_s	2 to 8 sections
Degree of high tension sectionalization	$\frac{N}{V}$	$\frac{\text{0.4 to 4.0 H.T.}^{*}\text{ bus sections}}{2830\ m^3/\text{min}}$ $\left(\text{0.4 to 4 } \frac{\text{H.T.}^{*}\text{ bus sections}}{\text{100,000 cfm}}\right)$

*H.T. = high tension

An average W_e value of about 6 to 9.1 cm/s (0.2 to 0.3 ft/s) is representative of recent installations designed for high collection efficiencies (99+ percent) where resistivity does not exceed about 2×10^{10} ohm-cm.

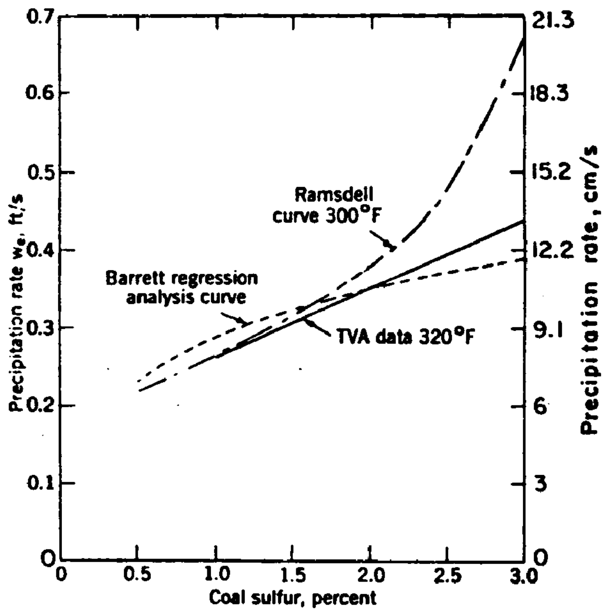

Figure 3. Relation of W_e to coal sulfur content for flue gas temperatures in the neighborhood of 149°C (300°F) as determined by several investigators.[14]

If one could rely solely upon plate area, A, volume flow rate, V, and average electrical migration velocity, w, to compute fly ash collection efficiencies by means of the well-known Deutch-Anderson (D-A) equation, collection efficiency would be estimated as:

$$\text{Efficiency} = \eta = 1 - \exp - (w\ A/V) \qquad (1)$$

In most cases, however, field data indicate lower efficiencies than predicted by the D-A relationship. To account for the observed particle collection levels, White[15] designates the empirical relationship:

$$\eta = 1 - \exp - (w_k\ A/V)^{0.5} \qquad (2)$$

as a more realistic predictor of particulate collection efficiency. The exponent, 0.5, is applicable when the ESP system is handling coal fly ash. In

Equation (2), the term w_k is an "effective" migration velocity computed from experimental measurements. This parameter results in a better estimate of SCA at high removal efficiencies.

The collection surface required for a given gas flow and efficiency may be estimated from Equation (2). Practical values of SCA range between 328 to 2630 $m^2/1000\ m^3/min$ (100 and 800 $ft^2/1000$ acfm) for most field applications.

Gas velocity in the precipitator is extremely important since collection is highly sensitive to velocity variations. The critical velocity depends on such factors as plate configuration and precipitator size and the judicious use of flow distributors is required to minimize velocity gradients. The design velocity limit for high efficiency fly ash precipitators is about 1.5 to 1.8 m/s (5 to 6 ft/s).

In general, the performance of a given ESP unit is a function of "the size of the box" (plate area and depth), the resistivity and size properties of the fly ash, the electrical parameters defining particle charge and field strength and proper operation and maintenance of equipment. Electrical controls are readily adjustable but are typically maintained at predetermined levels. The main reason for impaired system performance is faulty equipment maintenance. On the other hand, some degradation of system components with time is unavoidable. Since compliance testing is usually performed with all boiler and control device equipment properly tuned, cleaned and in good repair, true emission levels between testing intervals are difficult to predict except that they probably exceed compliance test levels.

Variations in fuel characteristics can play an important role in determining performance of an ESP. This is especially true of industrial boiler fuel supplies (as opposed to utility boilers) since the former will usually "spot" purchase coal rather than commit themselves to any long-term coal contracts. What this means is that industrial boilers can expect to see larger variations in coal properties (over time) than utility boilers, which, with an ESP for particulate control, will be reflected by the outlet concentrations. The most notable fuel properties are sulfur and alkali (primarily sodium) contents of the coal being burned, which affect the resistivity of the fly ash, as illustrated in Figures 4, 5, and 6.[16] Figures 4 and 5 show that resistivity is altered (lessened) favorably with increasing sulfur content or decreasing flue gas temperature. Figure 6 indicates the desirable effect of reduced resistivity with an increasing percentage sodium in the ash.

Consideration must also be given to other metal oxides and when designing specifically for an ESP application, it is desirable to preferentially select coals whose ash contents have high Na_2O (> 1.0 percent), Li_2O and Fe_2O_3, and low CaO, MgO (< 20 percent combined), SiO_2, and P_2O_5 (< 1.0 percent).

Most users (utilities) of ESP equipment have become very familiar with equipment operation over the years. Electrostatic precipitators account for at least half of the market in terms of particulate control equipment. Furthermore, there is a great deal of interaction between vendors and users that has resulted in many innovations and design improvements. Invariably, improvements in design result in better performance, such as zig-zag electrode configurations for improved electrification and gas flow distribution.

Current research and development is aimed primarily at improved voltage regulation through the use of automatic voltage control (a necessity whenever boiler load is expected to fluctuate). Improved electrode configurations that more efficiently distribute the charge while at the same time are better able to tolerate fly ash buildup, and innovations in rapper designs are also part

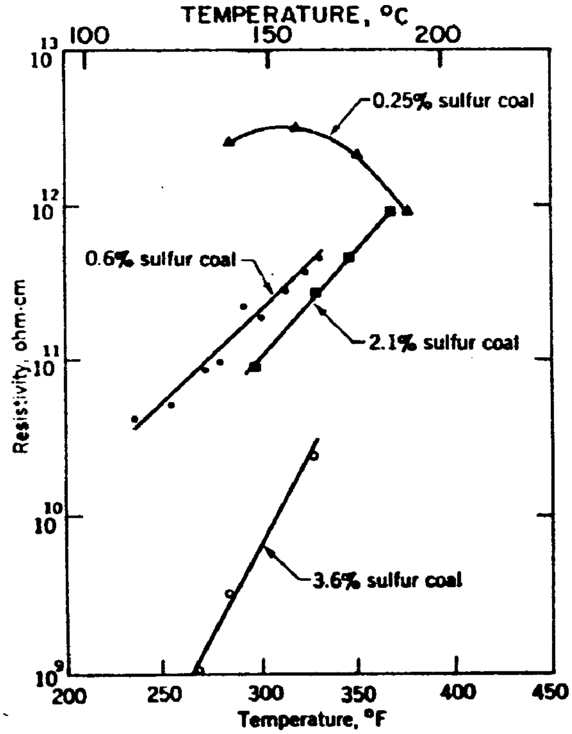

Figure 4. Variation of fly ash resistivity with temperature for coals of various sulfur contents.[16]

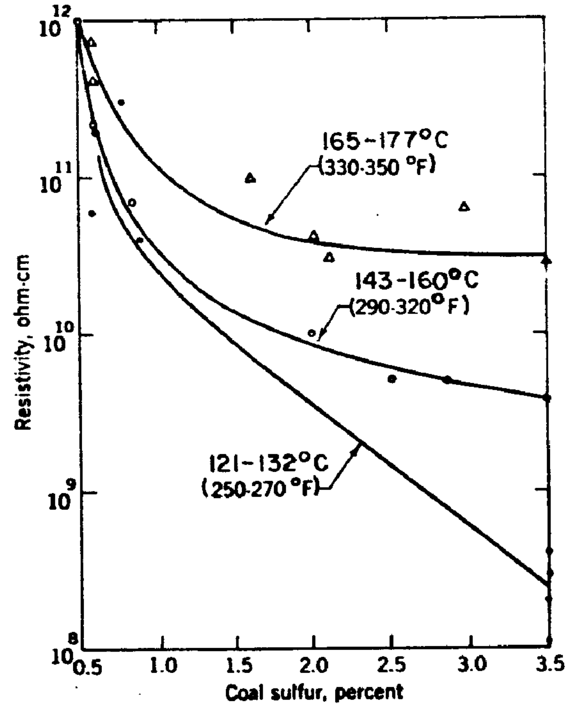

Figure 5. Fly ash resistivity versus coal sulfur content for several flue gas temperature bands.[16]

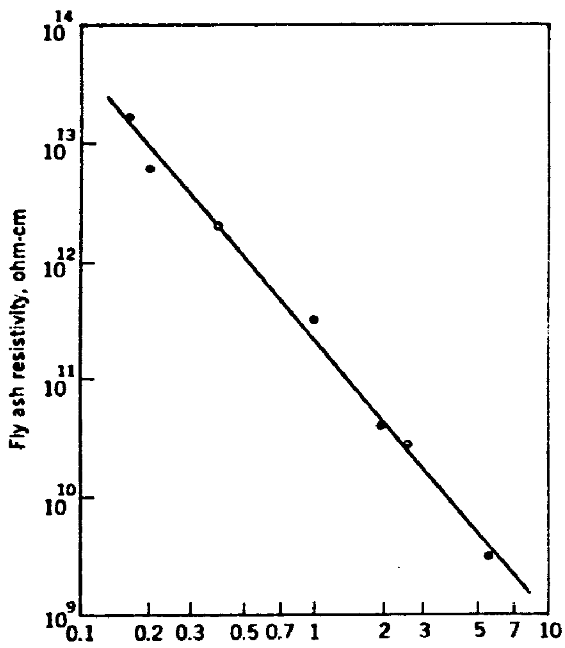

Figure 6. Variation of resistivity with sodium content for fly ash from power plants burning western coals.[16]

of the current R&D effort. In addition, there is vigorous activity in the area of improved charging concepts (e.g., bias pulse charging, pulsed energization, and precharging or preionization). The net result of all of these measures will, hopefully, be to improve overall collection efficiency.

The main problems with retrofit installations are space limitations and timing the control device installation with the scheduled boiler outage to minimize loss of capacity. With an ESP installation, space factors are critical if the duct work from the boiler to the control device is contorted to the extent that the gas flow into the ESP is no longer uniformly distributed. Space limitations can also affect the required installation time and therefore the overall project cost. Except in extreme cases, however, it is expected that most sources could be retrofitted successfully.

2.2.1.2 System Performance--

Most test data that are available for coal-fired boilers controlled by precipitators come from the utility rather than the industrial boiler sector. The fact that the power generated by a utility boiler is its sole product, whereas the industrial boiler output is only one of several factors contributing to the ultimate product cost, probably results in more careful regulation and more sophisticated operating procedures for the utility boiler and its emission control system. Additionally, load levels are more constant and shutdowns less frequent for the utility boiler. At the same time, the physical properties of the coals burned by utilities are less variable in that the fuel is purchased under long-term contracts with more rigid composition specifications. The three items cited above are expected to contribute to reduced emissions for utilities operations when the same fuel is burned. In the event that stoker firing is used, it is possible that those industrial boiler emissions may be lower than that seen with pulverized coal utility boilers because of the increased particle size with stoker-firing, and hence, greater ease of collectability in all collectors.

Furthermore, since most test data derive from compliance testing, they should be interpreted as representing the best possible system performance and not typical, day-to-day or average emission levels. The implication here is that few compliance tests are undertaken unless the system is operated under the following conditions: correct fuel at the rated load level; clean duct and electrode surfaces; all ionizing electrodes functioning; and no leaks or defective dampers in the gas handling system. In actual practice, real systems are subject to deviations from the above such that a gradual increase in emission levels probably occurs with increased on-line service.

A recent GCA report prepared for the Utility Air Regulatory Group of the Edison Electric Institute documented the performance capabilities of a large number of utility stations across the country controlled by electrostatic precipitators.[17] A comprehensive summary of these data is presented in Table 16. All boilers in this table are dry bottom units burning pulverized coal except Gannon units 5 and 6 (Tampa Electric Co.) which are pulverized wet bottom, and all units were designed to meet emission levels within the range being considered in this report. A plot of emission rate in ng/J ($lb/10^6$ Btu) versus specific collector area (SCA) for these tests is shown in Figure 7, but since the SCA values encountered were nonuniformly distributed over the reporting range, and because of other system variabilities, the correlation obtained was not significant. Other performance data for utility boilers burning lignite coals, Table 17, show ESP collection efficiencies ranging from 97 to 99.8 percent.[18]

TABLE 16. SUMMARY OF UARG SURVEY ESP TEST DATA[17]

Utility/Station	Control device: Installation date	Control device: Percent of time fully operational	Designed to meet: NSPS ($0.1\ lb/10^6\ Btu$)[a]	Designed to meet: State standard of ($lb/10^6\ Btu$)[a]	Tested emission rate ($lb/10^6\ Btu$)[a]	Type of source test: Compliance test by EPA Method 5	Type of source test: Stack test ASME power test code 27	Type of source test: Other test modification
1. American Electric Power Co.								
Glen Lyn No. 5	1974	100	X		0.003	X		
Glen Lyn No. 6	1975	100	X		0.001	X		
Amos No. 3	1973	58		0.05	0.04	X		
Big Sandy No. 1	1970	54		0.245	0.24	X		
Big Sandy No. 2	1969	100		0.19	0.17	X		
Clinch River No. 1	1975	4	X		0.05	X		
Clinch River No. 2	1974	0	X		0.05	X		
Clinch River No. 3	1974	0	X		0.05	X		
Gavin No. 1	1974	85	X		0.013	X		
Gavin No. 2	1975	88	X		0.014	X		
Kanawha R. No. 1	1969	73		0.05	0.03	X		
Kanawha R. No. 2	1969	100		0.05	0.03	X		
Tanners Cr. No. 1	1977	100	X		0.01	X		
Tanners Cr. No. 2	1977	100	X		0.01	X		
2. Consumers Power Co.								
Campbell No. 1	1976	NA		0.08-0.095	0.0354 gr/scf			X
Campbell No. 2	1978	NA		0.08-0.095	0.015 gr/scf			X
Campbell No. 3	1980	NA	X		0.06 gr/scf		not tested	
Whiting No. 1	1973	95		0.08-0.095	0.006 gr/scf			X
Whiting No. 2	1973	95		0.08-0.095	0.036 gr/scf			X
Whiting No. 3	1973	95		0.08-0.095	0.009 gr/scf			X
Karn No. 1	1976	NA		0.08-0.095	0.026 gr/scf			X
Karn No. 2	1976	NA		0.08-0.095	0.026 gr/scf			X
3. Cleveland Electric Co.								
Eastlake No. 5	1972	18		0.1	0.04		X	
4. Duke Power Co.								
Allen No. 3	1973	87		0.15	0.247[b]	X		
Allen No. 4	1972	7		0.15	0.324[b]	X		
Allen No. 5	1973	74		0.15	0.228[b]	X		
Belews Creek No. 1	1974	90		0.1	0.09			X
Belews Creek No. 2	1975	88		0.1	0.804[b]	X		
Buck 3 No. 5	1972	95		0.24	-			X
Buck 3 No. 6	1972	98		0.24	-			X
Buck 4 No. 7	1972	92		0.24	-			X
Buck 5 No. 8	1973	96		0.18	-			X
Buck 6 No. 9	1973	99		0.18	0.045			X
Cliffside No. 1	1972	88		0.24	0.042	X		
Cliffside No. 2	1972	79		0.24	0.18	X		
Cliffside No. 3	1973	98		0.21	0.094	X		
Cliffside No. 4	1973	98		0.21	0.133			X
Cliffside No. 5	1972	85		0.12	0.048			X

(continued)

TABLE 16 (continued)

Utility/Station	Control device: Installation date	Control device: Percent of time fully operational	Designed to meet: NSPS (0.1 lb/10^6 Btu)[a]	Designed to meet: State standard of (lb/10^6 Btu)[a]	Tested emission rate (lb/10^6 Btu)[a]	Type of source test: Compliance test by EPA Method 5	Type of source test: Stack test ASME power test code 27	Type of source test: Other test modification
4. Duke Power Co. (continued)								
Dan River No. 1	1971	99		0.21	0.134			X
Dan River No. 2	1971	NA		0.21	0.083			X
Dan River No. 3	1972	96		0.13	0.081			X
Lee No. 1	1970	100		0.6	0.10	X		
Lee No. 2	1970	100		0.6	0.11	X		
Lee No. 3	1973	100		0.6	0.12	X		
Marshall No. 3	1972	55		0.12	0.119	X		
Marshall No. 4	1972	70		0.12	-			X
Riverbend 4 No. 7	1973	86		0.24	-			X
Riverbend 4 No. 8	1972	98		0.24	0.046			X
Riverbend 6 No. 9	1972	75		0.23	-			X
Riverbend 7 No. 10	1973	84		0.23	0.042			X
5. Pennsylvania Power & Light Co.								
Montour No. 1 & No. 2	1971	80		0.1[c]	0.05-0.9			X
Brunner I. No. 1	1961/1965	70		0.1[d]	0.6-2.0			X
Brunner I. No. 2	1965/1976	>99[e]		0.1	0.086	X		
Sunbury No. 3	1952/1976	100		0.1	0.087	X		
Sunbury No. 4	1954/1975	100		0.1	0.26	X		
6. Public Service Co. of Colorado								
Arapahoe No. 1	1976	95		0.1	0.028			
Comanche No. 2	1975	70	X		0.04			
7. Salt River Project								
Navajo No. 1	1974	84			0.05			
Navajo No. 2	1975	79		0.06	0.071			
Navajo No. 3	1976	75			0.0471	X		
Hayden No. 2	1976	100	X		0.1-0.11			
8. Gulf Power Co.								
Crist No. 4	1968/1976	NA		0.1	0.033	X		
Crist No. 5	1969/1976	NA		0.1	0.082	X		
Crist No. 6	1970	NA		0.1	0.085	X		
Crist No. 7	1973	NA		0.1	0.099	X		
Lansing Smith No. 1	1965/1976	NA		0.1	0.043	X		
Lansing Smith No. 2	1967/1977	NA		0.1	-	X		
Scholz No. 1	1974	NA		0.1	0.019	X		
Scholz No. 2	1974	NA		0.1	0.075	X		
9. Tampa Electric Co.								
Gannon No. 5	1975	NA		0.1	0.06	X		X
Gannon No. 6	1974	NA		0.1	0.06	X		

(continued)

TABLE 16 (continued)

Utility/Station	Control device: Installation date	Control device: Percent of time fully operational	Designed to meet: NSPS (0.1 lb/10^6 Btu)[a]	Designed to meet: State standard of (lb/10^6 Btu)[a]	Tested emission rate (lb/10^6 Btu)[a]	Type of source test: Compliance test by EPA Method 5	Type of source test: Stack test ASME power test code 27	Type of source test: Other test modification
10. Tennessee Valley Authority								
Allen No. 1	1972	95		0.1-0.14	0.05			X
Colbert No. 2	1972	94		0.1-0.14	0.06	X		
Colbert No. 3	1972	92		0.1-0.14	0.096	X		
Colbert No. 4	1972	91		0.1-0.14	0.088	X		
Colbert No. 5	1976	85		0.1-0.14	0.08	X		
Cumberland No. 1	1972	84		0.1-0.14	0.12			X
Cumberland No. 2	1973	73		0.1-0.14	0.12			X
John Sevier No. 1[f]	1973	93		0.1-0.14	0.013			X
John Sevier No. 2[f]	1973	98		0.1-0.14	0.021			X
John Sevier No. 3[f]	1974	96		0.1-0.14	0.026			X
John Sevier No. 4[f]	1974	96		0.1-0.14	0.008			X
Johnsonville No. 1[f]	1976	97		0.1-0.14	0.04			X
Johnsonville No. 2[f]	1976	99		0.1-0.14	0.01			X
Johnsonville No. 3[f]	1951/1976	98		0.1-0.14	0.03			X
Johnsonville No. 4[f]	1952/1976	96		0.1-0.14	0.03			X
Johnsonville No. 5[f]	1952/1975	99		0.1-0.14	0.03			X
Johnsonville No. 6[f]	1952/1975	96		0.1-0.14	0.03			X
Johnsonville No. 7[f]	1958/1974	71		0.1-0.14	0.18			X
Johnsonville No. 8[f]	/1974	86		0.1-0.14	0.06			X
Johnsonville No. 9[f]	/1974	91		0.1-0.14	0.05			X
Johnsonville No. 10[f]	/1974	89		0.1-0.14	0.07			X
Kingston No. 1[f]	/1976	NA		0.1-0.14	-			X
Kingston No. 2[f]	/1976	99		0.1-0.14	0.027			X
Kingston No. 3[f]	/1976	94		0.1-0.14	0.019			X
Kingston No. 4[f]	/1976	NA		0.1-0.14	-			X
Kingston No. 5[f]	/1976	NA		0.1-0.14	0.012			X
Kingston No. 6[f]	/1976	98		0.1-0.14	0.017			X
Kingston No. 7[f]	/1976	91		0.1-0.14	0.015			X
Kingston No. 8[f]	/1976	94		0.1-0.14	0.012			X
Kingston No. 9[f]	/1976	98		0.1-0.14	0.01			X
11. Virginia Electric and Power								
Mt. Storm No. 1	1973	95		0.05	0.025		X	
Mt. Storm No. 2	1973	94		0.05	0.045		X	
Mt. Storm No. 3	1973	91		0.05	0.113			X
Chesterfield No. 6	1969	28		0.1	0.04		X	
Bremo No. 3	1973	0		~0.15	0.022		X	
Bremo No. 4	1973	20			0.022		X	

(continued)

TABLE 16 (continued)

Utility/Station	Control device		Designed to meet:		Tested emission rate ($lb/10^6$ Btu)[a]	Type of source test		
	Installation date	Percent of time fully operational	NSPS (0.1 $lb/10^6$ Btu)[a]	State standard of ($lb/10^6$ Btu)[a]		Compliance test by EPA Method 5	Stack test ASME power test code 27	Other test modifications
ADDENDUM								
Union Electric Co.								
Rush Island No. 1	1976	59	X		0.04	X		
Rush Island No. 2	1977	94	X		0.06	X		
Iowa Public Service Co.								
Neal 1	1971	70		0.583[g]	0.458	X		
Neal 2	1971	95		0.380[g]	0.178	X		
Neal 3	1975	95		0.439[g]	0.039	X		
Neal 4	1979	--	X	-	-			
Kansas City P&L Co. Kansas Gas & Elec. Co.								
LaCygne No. 2	1977	>99[h]	X		0.012	X		
Kansas City P&L Co.								
Hawthorn No. 1	1977	100[h]		City-0.18[i]	0.014	X		
Hawthorn No. 2	1977	100[h]		City-0.18[i]	0.022	X		

[a] 0.1 $lb/10^6$ Btu = 43 ng/J. To convert from $lb/10^6$ Btu to ng/J multiply by 430.

[b] Not considered representative of current performance.

[c] Experimenting with Apollo additives

[d] With and without SO_3 injection.

[e] Confidential!

[f] Preceded by mechanical collectors.

[g] Allowable emissions based on multiple stack. Design efficiencies are 99.0, 99.0, and 99.7 percent, respectively.

[h] Percent of time all fields operational is not available.

[i] State requires 0.12 for station average.

NA = Not Applicable.

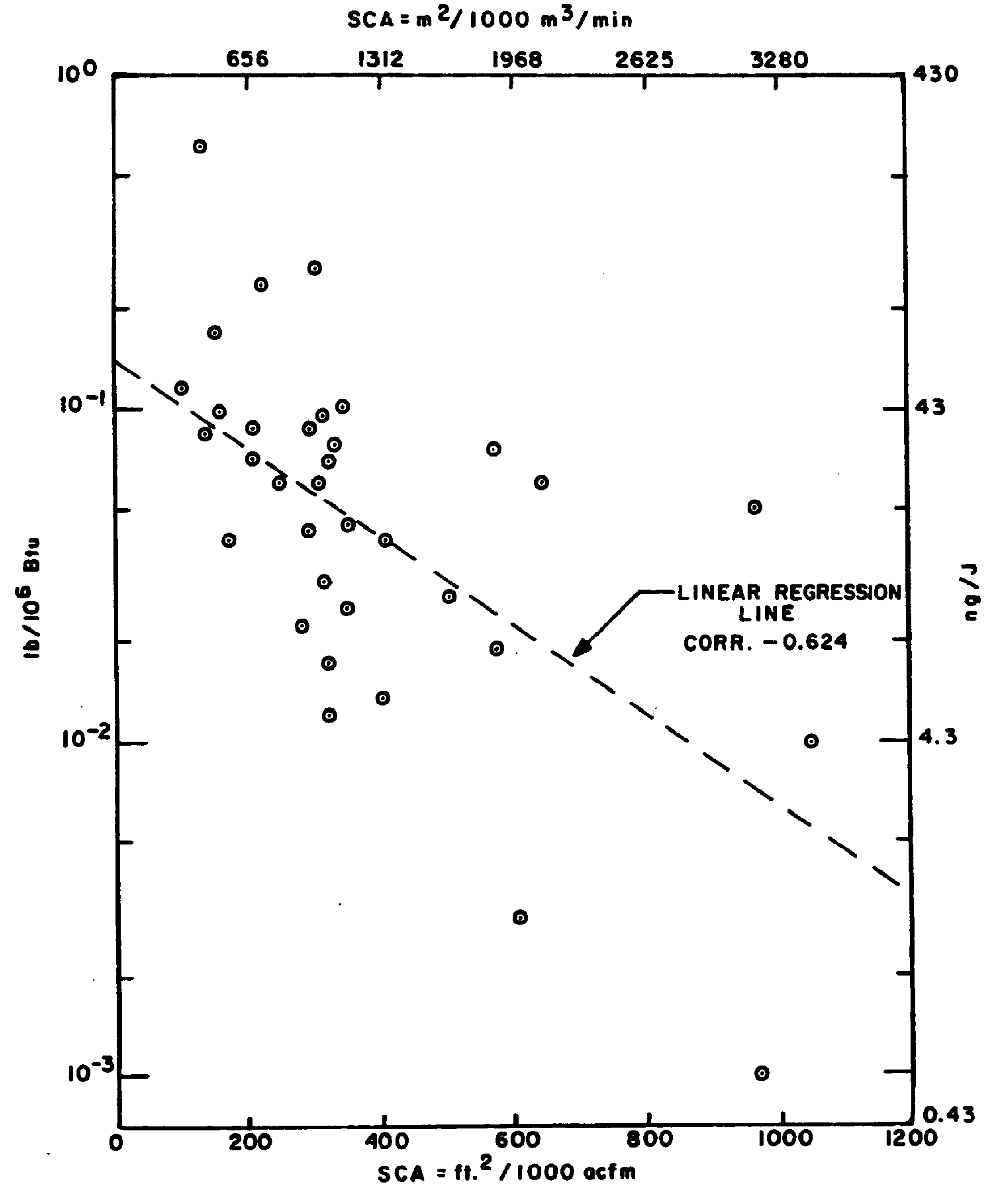

Figure 7. Emission rate versus specific collector area (SCA) based on UARG survey.[17]

TABLE 17. DESIGN AND TEST DATA FOR ELECTROSTATIC PRECIPITATORS IN OPERATION OR PLANNED FOR POWERPLANTS BURNING NORTH DAKOTA LIGNITES[18]

Utility company	Basin Electric Power Cooperative		Minnkota Power Cooperative		Otter Tail Power				Montana Dakota Utilities		United Power Association
Station	Leland Olds No. 1	Leland Olds No. 2	Milton R. Young No. 1	Milton R. Young No. 2	Hoot Lake No. 2	Hoot Lake No. 3	Ortonville	Big Stone	Heskett No. 1	Heskett No. 2	UPA - Stanton
Location	Stanton, North Dakota		Center, North Dakota		Fergus Falls, Minnesota		Ortonville, Minnesota	Milbank, South Dakota	Mandan, North Dakota		Stanton, North Dakota
ESP installation on new or existing boiler	Existing	New	Existing	New	Existing	Existing	Existing	New	Existing	Existing, ESP in series with mechanical collector	Existing
ESP vendor	Research-Cottrell	Western	Research-Cottrell	Wheel-abrator	Research-Cottrell	Research-Cottrell	Research-Cottrell	Wheel-abrator	Research-Cottrell	Research-Cottrell	Research-Cottrell
Completion date	11/74	9/75	6/75	5/77	5/72	4/72	6/72	5/75	6/75	6/75	5/76
Boiler capacity (MW)	215	440	235	438	61	79	21	440	25	66	160
Firing method	pc	cyclone	cyclone	cyclone	pc	pc	spreader-stoker	cyclone	spreader-stoker	spreader-stoker	pc
Number of transformer-rectifier sets	16	40	16	32	4	4	4	24	6	10	12
Flue gas											
Temperature, °F	360	373	385	380	330	310	345	288	418	333	350
°C	(182)	(189)	(196)	(193)	(166)	(154)	(174)	(142)	(214)	(167)	(177)
Velocity, ft/sec*	5.01	5.00	5.55	5.00	4.23	5.07	4.25	5.25	3.80	4.28	5.17
(m/sec)	(1.53)	(1.52)	(1.69)	(1.52)	(1.29)	(3.28)	(1.30)	(1.60)	(1.16)	(1.30)	(1.58)
Flow, ft^3/min†	1,000,000	2,100,000	1,170,000	2,200,000	280,000	390,000	133,000	2,330,000	189,300	451,800	853,750
(m^3/min)	(28,300)	(59,500)	(33,100)	(62,300)	(7,900)	(11,000)	(3,800)	(66,000)	(5,400)	(12,800)	(24,200)
Specific collecting area $ft^2/1000\text{-}ft^3/min$†	320	267	288	375	252	236	280	355	352	280	235
($m^2/1000\text{-}m^3/min$)	(1050)	(876)	(945)	(1230)	(827)	(774)	(919)	(1165)	(1155)	(919)	(771)
Inlet loading, gr/ft^3†	2.30	1.30	1.00	1.0 to 2.7	1.87	2.09	0.97	1.17	2.5 to 4.1	0.3 to 0.6	NA
(g/m^3)	(5.26)	(2.97)	(2.29)	(2.29 to 6.18)	(4.28)	(4.78)	(2.22)	(2.68)	(5.72 to 9.38)	(0.69 to 1.38)	NA
Outlet loading, gr/ft^3†	0.0125	0.0125	0.01	0.006	0.015	0.015	0.0042	0.014	0.0225	0.021	NA
(g/m^3)	(0.0286)	(0.0286)	(0.0229)	(0.0137)	(0.0343)	(0.0343)	(0.0096)	(0.0320)	(0.0515)	(0.0480)	NA
Design efficiency (%)	99.50	99.05	99.00	99.40	98.50	98.50	98.90	98.80	99.45	97.00	98.0
Measured efficiency	99.45%	NA	99.82%	NA	99.00%	99% +	99% +	99.63%	0.1 gr/ft^3	0.1 gr/ft^3	NA
Migration velocity, cm/sec	8.26	NA	11.15	NA	9.28	9.9	8.4	8.01	NA	NA	NA

*Volume flow rate at the entering flue gas temperature divided by cross-sectional area of precipitator.

†Flue gas volumes are computed at the entering flue gas temperature.

Note: NA = Data not available.

Performance statistics from Research-Cottrell are shown in Figure 8[19] for hot-side precipitator applications, and the relatively poorer performance on western coals as opposed to eastern coals should be noted. Unfavorable distributions of alkali metals as well as reduced sulfur levels, probably account for the diminished efficiencies for western applications. The data set shown for western coals represent hot precipitator installations on pulverized coal boilers before corrective actions were taken. The investigations leading to the causes and correction of the performance deficiencies encountered at two of these plants have significantly enhanced the vendor's knowledge relating to proper application of precipitators for western low sulfur coals.

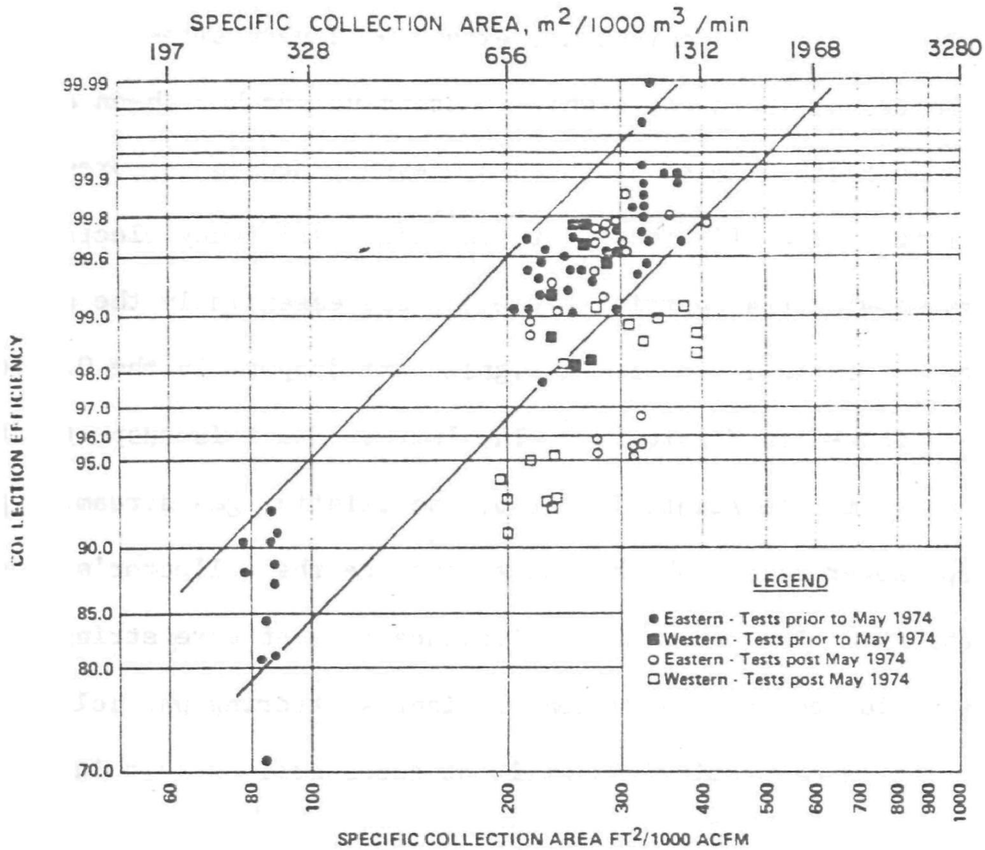

Figure 8. Actual performance data for Research-Cottrell hot precipitators, 1967 to 1976.[19]

Lodge-Cottrell (Dresser Industries, Inc.), another leading equipment supplier, offers only cold-side units and has had reasonable success on all coal types. Limited test data for five boilers are shown in the addendum to Table 16. These five boilers each burn < 1 percent sulfur coal and were designed for efficiencies of about 99.6 percent.

In discussing performance, reference must be made to visible emissions since opacity standards almost always accompany mass emission limits. Plume opacity is usually associated with the fine (< 2 μm and predominantly submicrometer) fractions of stack emissions which, because of their extended particle surface, have the capacity to absorb and/or scatter incident light. The data currently being studied at GCA indicate very little correlation between mass and visible emissions, except on a very site-specific basis. In fact, there have been cases where opacity values have been excessive even though mass emission limits had been achieved. McCain has presented fractional particle size efficiency data for high efficiency electrostatic precipitators showing that particle removals are essentially the same for the size range < 1 μm to 10 μm with a significant dropoff in the 0.1 to 1.0 μm range as indicated in Figure 9.[20] The latter effect is suspected to be the result of agglomerate reentrainment by the existing gas stream, bypass leakage and sparkover events which tend to obscure the collector's true collection capability. Improving ESP performance to meet more stringent mass standards would reduce penetration of light scattering particles. However, the reduction in mass emissions will not necessarily result in a proportional reduction in opacity. One utility plant has found the opacity from the stack to be dependent on the sodium (Na) content of the ash, with > 2 percent Na resulting in visible emissions.[21] The role of the sodium (as shown earlier

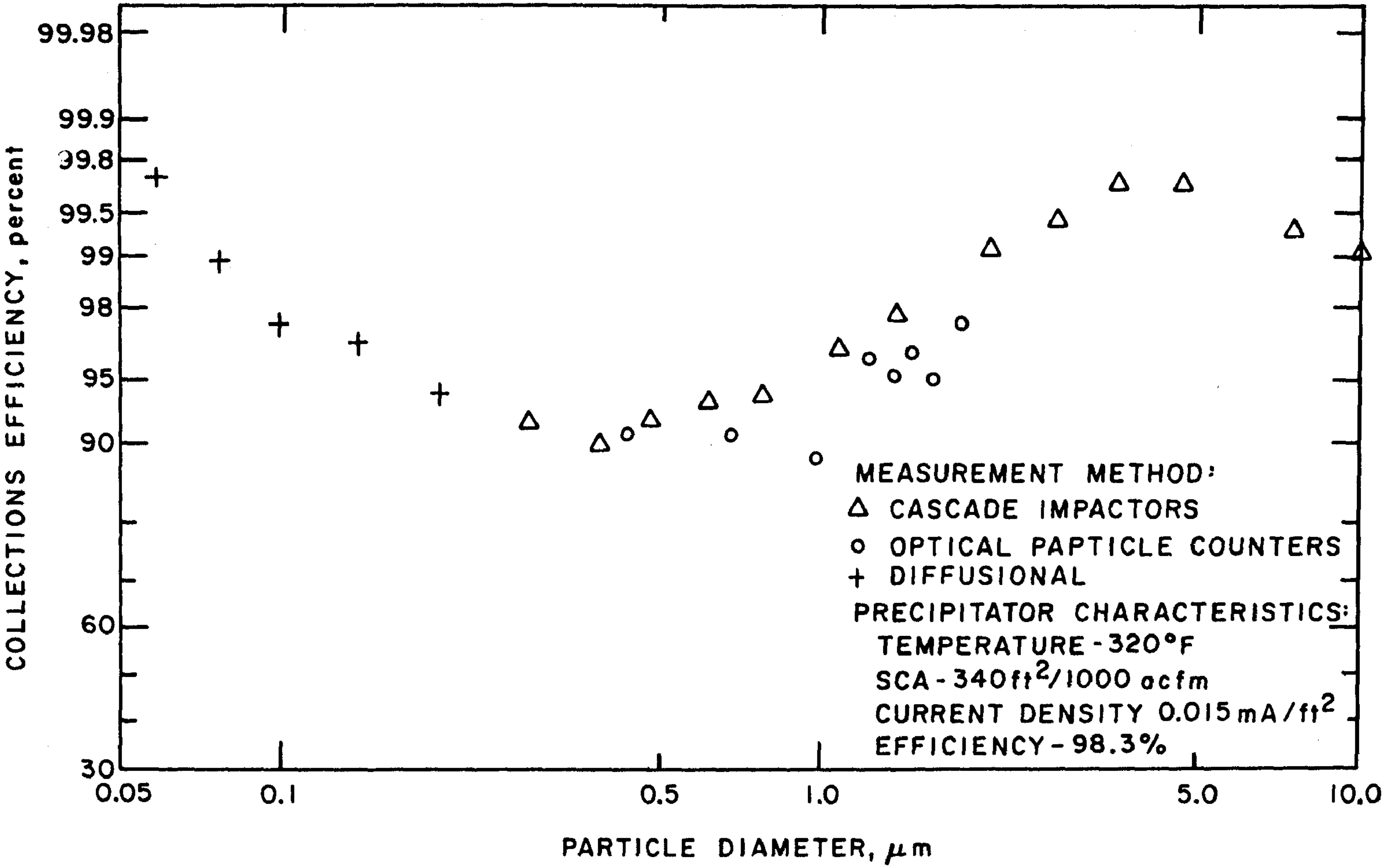

Figure 9. Measured fractional efficiencies for a cold-side ESP with operating parameters as indicated, installed on a pulverized coal boiler burning low sulfur coal.[20]

in Figure 6) appears to be mainly that of a dust-cake conditioner such that reduced ash resistivity improves the precipitating capacity of the system.

Other performance testing of high efficiency (99.8 to 99.9) electrostatic precipitators on coal-fired boilers indicated that significant portions of mass emissions were caused by reentrainment of coarse particles during the rapping of collector plates.[22,23] For hot side units, 60 to 80 percent of total mass emissions originated from the rapping sequence in contrast to about 30 percent for cold side precipitators. Most of the reentrained particulates, which were larger than 2 micrometers, were identified as major contributors to overall mass penetration in the high efficiency collectors. This mode of particle penetration would tend to obscure the effect of other ESP design and operating characteristics.

Energy requirements for ESP units are discussed in terms of corona power and gas handling capacity. Corona power is usually expressed in terms of energy per unit flow volume or plate area. Two curves based upon actual field test data show the energy-efficiency relationship, Figures 10 and 11.[24] Figure 10 depicts this correlation for actual field test data. Figure 11 shows the same relationship extrapolated to include efficiencies above 99 percent and demonstrates the nonlinearity of this function when very high efficiencies are obtained.

The performance data presented here show that emission levels down to 4.3 ng/J (0.01 lb/10^6 Btu) and below (in rare instances) are achievable with ESP technology applied to coal-fired boilers. Usually, the installation of control equipment involves additional requirements such as added manpower for operation and maintenance and monitors for pressure drop, temperature, and opacity. Because cold side precipitators are sensitive to corrosion,

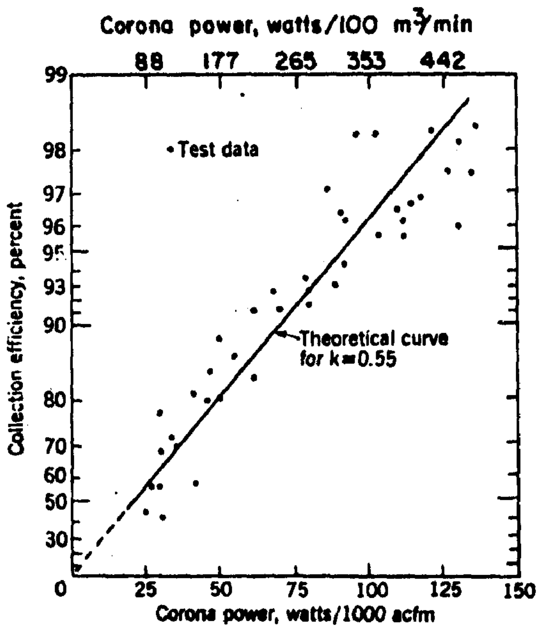

Figure 10. Relationship between collection efficiency and specific corona power for fly ash precipitators, based on field test data.[24]

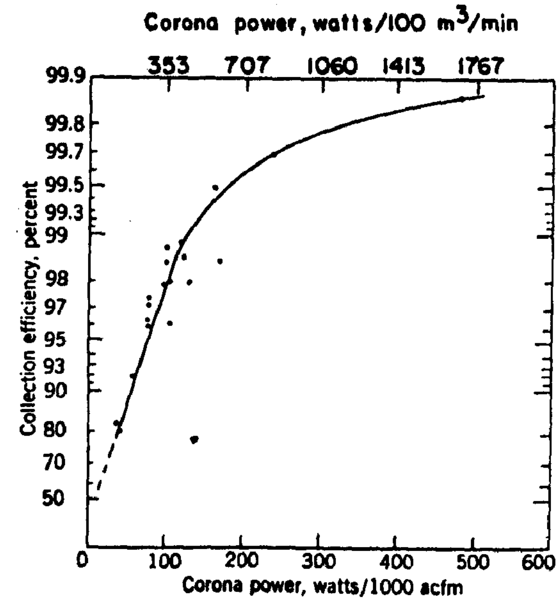

Figure 11. Efficiency versus specific corona power extended to high collection efficiencies, based on field test data on recently installed precipitators.[24]

they should be fully insulated to avoid heat loss. Generally, these added requirements present no unusual problems.

Vendors supplying ESP equipment will guarantee an emission level or an efficiency at a specified boiler steam load or air flow. A typical guarantee might include an emission rate of 43 ng/J (0.1 $lb/10^6$ Btu) or 0.07 g/Nm^3 (0.03 gr/scfd) and a 20 percent opacity. These guarantees usually apply to specific ranges in gas flow rate and/or fuel properties.

For the most part, the performance data reported here are for utility boiler emissions. Although these data should represent the approximate capabilities of ESP equipment as applied to industrial boilers, the previously cited differences in boiler size and variations in load level and fuel composition suggest that higher emissions might be encountered in industrial applications. The differences in terms of system size and inlet loadings, however, should present few engineering problems in applying ESP technology.

2.2.2 Fabric Filtration

2.2.2.1 System Description--

The basic mechanisms available for filtration are inertial impaction, diffusion, direct interception, and sieving. The first three processes prevail only briefly during the first few minutes of filtration with new or just cleaned fabrics while the sieving action of the dust layer accumulating on the fabric surface soon predominates, particularly at high, $> 1\ g/m^3$ (0.437 gr/ft^3) dust loadings. The latter process, in the case of coal fly ash filtration, leads to high efficiency collection unless defects such as pinhole leaks or cracks appear in the filter cake.[25]

An isometric view of a pulse-jet fabric filtration unit is shown in Figure 12,[26] while a reverse air baghouse is shown in Figure 13. A baghouse

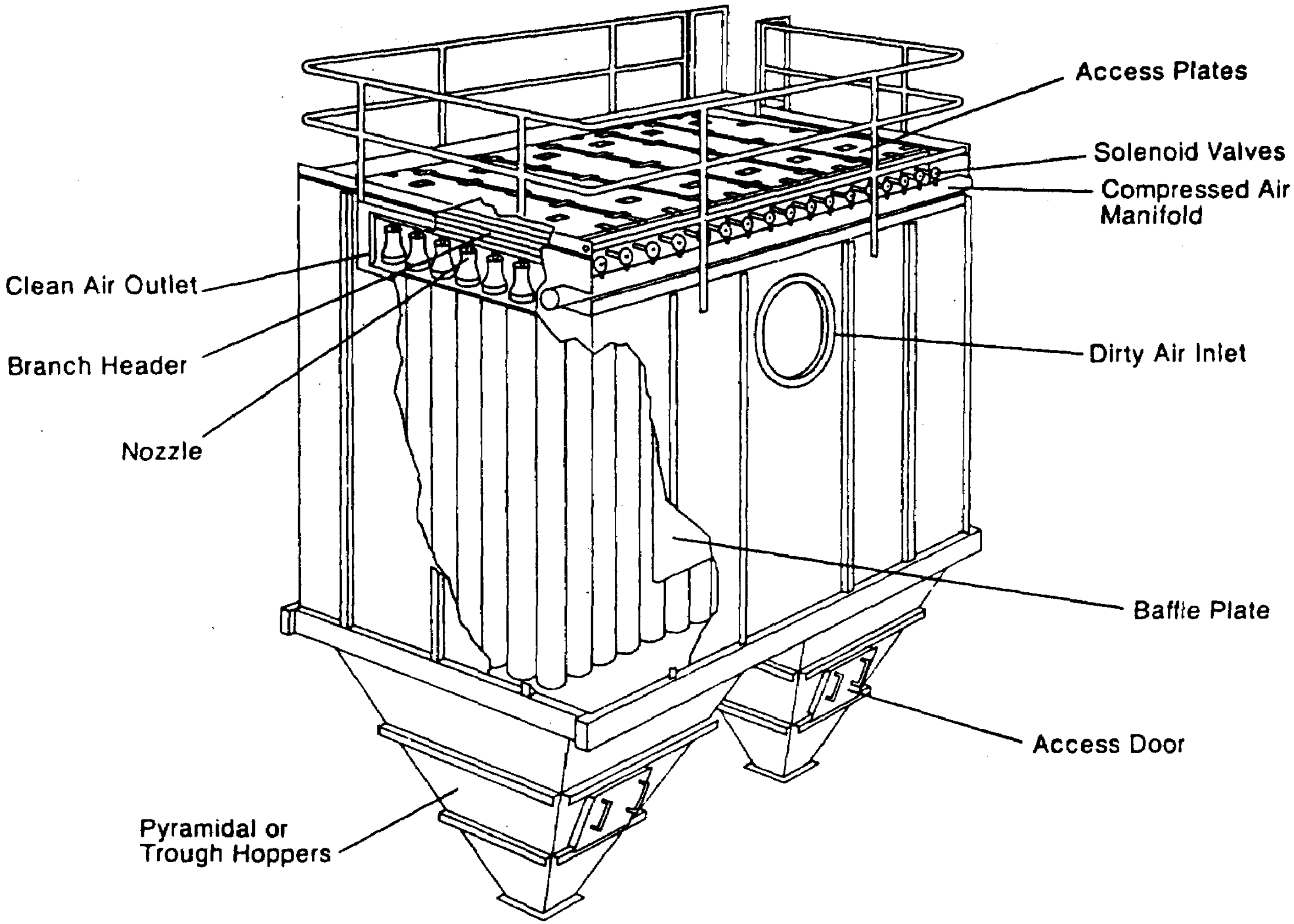

Figure 12. Isometric view of a two-compartment pulse-jet fabric filter.[26]

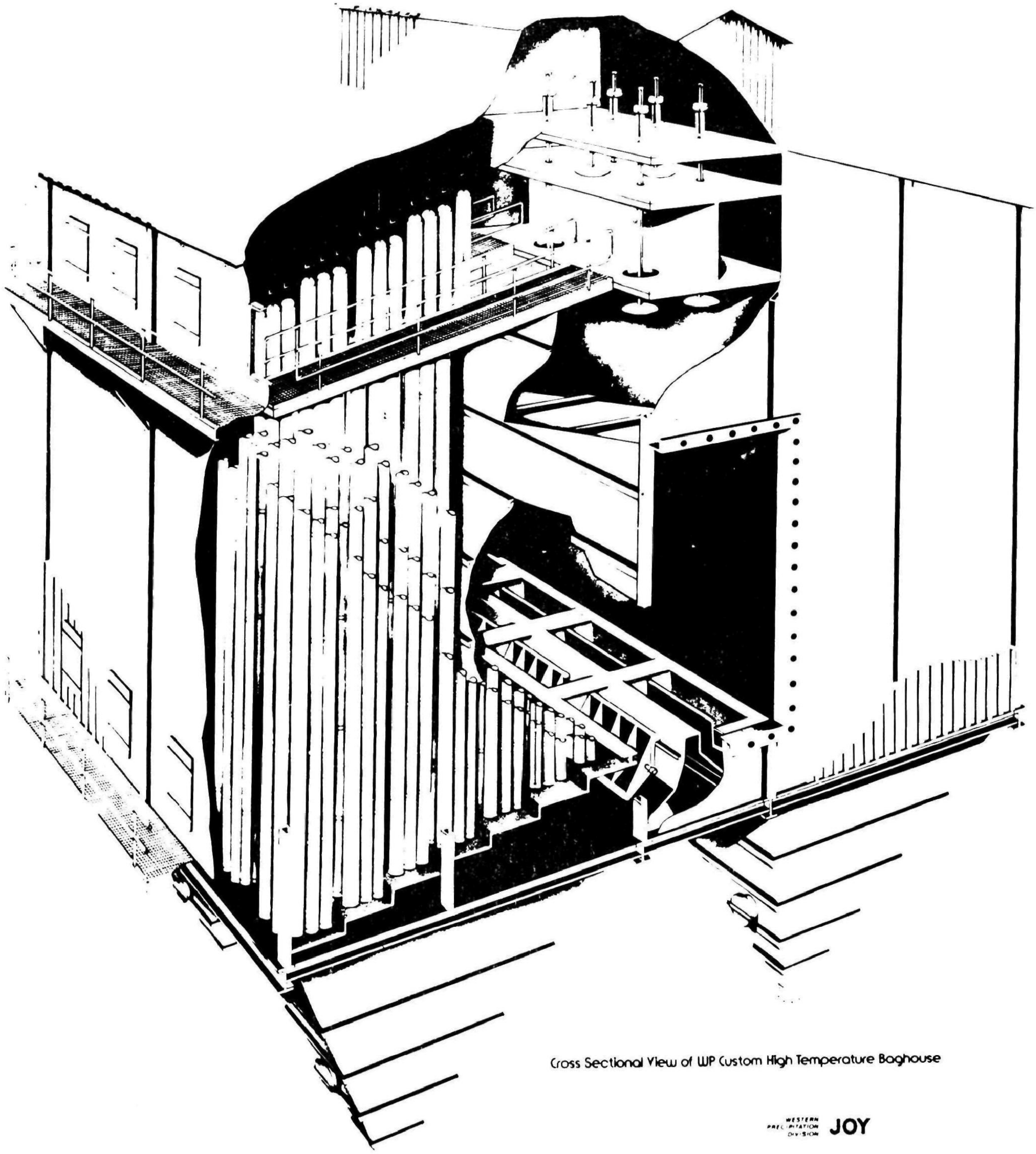

Figure 13. Cutaway view of a reverse air baghouse (courtesy of Western Percipitation Division, Joy Industrial Equipment Company).

consists of a number of filtering elements (bags) arranged in compartments, a cleaning mechanism or subsystem and the main shell structure and hoppers. The bags used in coal-fired boiler applications are usually fiberglass with a coating of silicone, graphite, and/or Teflon. One-hundred percent Teflon fabrics have had limited field applications since their cost has discouraged broad usage. The bag material is most important since the bags are usually the highest maintenance cost component. It has been estimated that bag lives of 2 or more years are required in order for fabric filtration to be competitive with electrostatic precipitation,[27] assuming that the latter approach can satisfy emission regulations. The cleaning processes used in coal-fired systems ordinarily consist of reverse-flow with bag collapse, and mechanical shaking sometimes in combination with each other. Pulse-jet cleaning also has had considerable application while the reverse jet concept (travelling blow ring) has seen limited field trials. The pulse-jet cleaning method is distinguished from the others in that (a) it is almost always used in conjunction with felted fabrics, 0.54 to 0.81 kg/m^2, (16 to 24 oz/yd^2) and (b) pulse-jet systems can operate at much higher filtration velocities, 1.2 to 2.4 m/min (4 to 8 ft/min) or greater, depending upon the dust characteristics. Mechanical shaking, which is normally used with woven fabrics, 0.27 to 0.41 kg/m^2, (8 to 12 oz/yd^2) requires generally lower filtration velocities, usually less than 1.2 m/min (4 ft/min).

Fabric filtration is a well-established technology with early industrial process applications dating back to the late 1800's. However, application to boiler effluents has been a recent endeavor with the first successful installations designed in the late 1960's and early 1970's. For example, available statistics on air pollution control costs by fabric filtration show that in

1977 the industrial boiler sector spent only $5 million dollars in contrast to $146 million for all industries combined.[28] For comparison, in 1972 total fabric filtration sales in the United States were about $53 million.

Although fabric filbration has only recently been applied to coal-fired boilers, limited field performance data have so far been encouraging for both stoker and pulverized coal boilers. At the present time, there are about 39 utility boilers equipped with baghouses with another 25 scheduled for installation or under construction. These facilities are listed in Table 18 along with their key operating parameters. The data sources were equipment vendors, various newsletters, and an article appearing in the January 1977 issue of Power magazine.

There are approximately 100 industrial boilers at 61 locations employing or planning on using fabric filtration systems and these units are shown in Table 19. Of the total, there are 55 stoker-fired units, and 25 pulverized-coal units. As indicated in Tables 18 and 19, the controlled boilers range in size from 100 hp to 575 MW (electric) with flue gas rates of 9,345 to 6.3×10^6 m^3/hr (5,500 to 3.68×10^6 acfm). Sulfur contents vary from 0.5 to 3.2 percent (not listed in these tables).

The basic parameters taken into consideration in the design of fabric filter systems are as follows:[29]

1. Dust properties and concentration
2. Gas stream temperature, pressure, and composition
3. Fabric material
4. Cleaning method
5. Gas-to-cloth ratio
6. Positive or negative pressure system
7. Materials handling

TABLE 18. BAGHOUSE INSTALLATIONS ON UTILITY BOILERS — U.S.

	Name/location	Manu-facturer	Cleaning mechanism	Boiler firing method	Size $(MW)_e$	A/C*	acfm†	Startup date
1.	Board of Public Utilities Kansas City, Kans.	Tbd	Tbd	PC	44	Tbd	300,000	1979
2.	Central Telephone and Utilities Corp. Pueblo, Colo.	MP	Tbd	S	20	Tbd	Tbd	1979
3.	City of Colorado Springs Colorado Springs, Colo.	WP	RA	PC	200	1.9/1	1.0×10^6	1980
4.	City of Colorado Springs Colorado Springs, Colo.	EB	Tbd	PC	85	Tbd	400,000	1978
5.	City of Columbia Columbia, Mo.	CAR	RA	(2)-PC	(2)-40	2.75/1	264,900	1979
6.	City of Fremont Fremont, Nebr.	CAR	RA	(2)-PC	(2)-38.5	2.6/1	270,000	1978
7.	City of Rochester Rochester, Minn.	CAR	RA	(1)-S	(1)-16	2.43/1	160,000	1978
8.	Colorado-Ute Electric Assoc. Craig No. 3	Tbd	Tbd	PC	400	Tbd	Tbd	1981
9.	Colorado-Ute Electric Assoc. Nucla, Colo.	WF	RA, sa	(3)-S	(3)-39	2.8/1	258,000	1973
10.	Colorado-Ute Electric Assoc. Montrose, Colo.	ICA	RA	2-PC	2-12	3/1	44,000	1977
11.	Crisp County Power Co. Cordele, Ga.	ZU	RA	PC	10	3.1/1	60,000	1975
12.	Golden Valley Electric Assoc. Healey No. 1 Fairbanks, Alas.	ICA	Tbd	PC	20	Tbd	Tbd	1980
13.	Marquette Board of Light and Power Shiras No. 3 Marquette, Mich.	Tbd	Tbd	PC	40	Tbd	Tbd	1982
14.	Minnesota Power & Light Cohasset, Minn.	WP	Tbd	(2)-PC	(2)-75	Tbd	348,000	1978
15.	Montana-Dakota Utilities Coyote Station, Buelah, N. Dak.	WF	RA, sa	C	440	2.49/1	1.9×10^6	1981
16.	Nebraska Public Power Kramer Station Bellevue, Nebr.	ICA	RA	(4)-PC	(4)-113 each	1.7/1	558,000	1978
17.	Ohio Edison Company W. H. Sammis Station Stratton, Ohio	AAF	RA	-	(4)-185 each	2/1	~ 600,000 each	1982
18.	Pennsylvania Power & Light Brunner's Island Allentown, Pa.	CAR	RA	PC	350	2.31/1	1.2×10^6	1980
19.	Pennsylvania Power & Light Holtwood, Pa.	WF	RA, sa	PC	79	2.3/1	235,000	1975
20.	Pennsylvania Power & Light Sunbury Station Shamokin Dam, Pa.	WP	RA	(4)-PC	(4)-175	1.9/1	888,000	1973
21.	Public Service of Colorado Cameo No. 1 Palisade, Colo.	CAR	RA	PC	22	2.85/1	170,000	1978

(continued)

TABLE 18 (continued)

	Name/location	Manu- facturer	Cleaning mechanism	Boiler firing method	Size $(MW)_e$	A/C*	acfm†	Startup date
22.	Sierra Pacific Power Co. North Valley No. 1 Reno, Nev.	CAR	RA	PC	250	2.71/1	1.246×10^6	1980
23.	South California Edison Alamitos Station Long Beach, Calif.	ME	RA	OF & GF	320	5.7/1	820,000	1965
24.	Southwestern Public Service Harrington Station Amarillo, Tex.	WF	RA, sa	(2)-PC	(2)-350 each	3.27/1	1.65×10^6	1978-1979
25.	Tennessee Valley Authority Shawnee Steam Plant	EB	RA	(10)-PC	175 each	1.84/1	6.5×10^5 each	1981
26.	Texas Utilities Monticello, Tex.	WF	RA, sa	(2)-PC	(2)-575 each	2.71/1	3.68×10^6	1977
27.	United Power Association Coal Creek Station	WF	RA, sa	(2)-S	(2)-26	2.94/1	175,000	1977
28.	Pennsylvania Power & Light‡ Holtwood Sta., Allentown, Pa.	F	-	PC	79	-	235,000	-
29.	Public Service of Colorado Cameo Station	WP	-	-	-	-	-	August 1979
30.	Baltimore Gas & Electric Wagner Station No. 3	EE		pilot installation				May 1979
31.	Houston Lighting & Power Parish Station No. 8	RC	RA	PC	550	2/1	2.2×10^6	May 1983
32.	United Power Association Elk River Station	RC	RA	1-PC 2-S	3-48	2.45/1	255,800	1978
33.	Marquette Board of Light & Power Shiras No. 1 & 2, Marquette, MI	AAF	-	-	-	-	-	1979
34.	Kansas City Power & Light Kansas City, MO	2-ICA 1-EB	-	-	3-140	-	-	1979

*A/C - given in ft/min. To convert to m/min, multiply by 0.3048

†To convert acfm to m^3/hr, multiply by 1.699

‡To be installed in parallel with existing baghouse and will handle 60 percent of the emissions and will replace existing wet scrubber.

Manufacturers

AAF - American Air Filter
CAR - Carborundum Co.
EB - Envirotech-Buell Div.
ICA - Industrial Clean Air, Inc.
ME - Menardi Southern
WF - Wheelabrator-Frye, Inc.
WP - Joy Mfg. Co.-Western Precip. Div.
ZU - Zurn Industries
F - Fuller Co.
EE - Environmental Elements
RC - Research-Cottrell
MP - MicroPul

Symbols

A/C - air-cloth ratio
c - cyclone-fired
GF - gas-fired
OF - oil-fired
PC - pulverized coal
RA - reverse air
RA, sa - reverse air, shake assist
S - stoker
Tbd - To be determined

TABLE 19. BAGHOUSE INSTALLATIONS ON INDUSTRIAL BOILERS — U.S.

	Name/location	Manufacturer	Cleaning mechanism	Boiler firing method	Size $(MW)_e$	A/C*	acfm†	Startup date
1.	Adolph Coors Co. Golden, Colo.	WF	RA, sa	PC	33	2.3/1	150,000	1976
2.	Allied Chemical Southpoint, Ohio	WF	RA, sa	PC	(6)-12	2.99/1	59,000	1978
3.	Allied Chemical Moundsville, W. Va.	WF	RA, sa	S	(4)-32	2.89/1	156,400	1978
4.	Amalgamated Sugar Co. Nampa, Idaho	WP	RA	PC	28	2.4/1	126,000	1974
5.	Amalgamated Sugar Co. Nampa, Idaho	EB	Sh	PC	29	2.5/1	130,000	1975
6.	Amalgamated Sugar Co. Nyssa, Oreg.	WF	RA, sa	S	21	3.56/1	92,000	1973
7.	Amalgamated Sugar Co. Nyssa, Oreg.	WP	RA	PC	13	2/1	57,000	1975
8.	Amalgamated Sugar Co. Twin Falls, Idaho	WP	RA	1-PC 1-S	21 each	2.5/1	100,000 each	1975
9.	Ametek, Inc. Moline, Ill.	AAF	RA	S	9	4/1	40,000	1974
10.	Ashland Chemical Co. Peoria, Ill.	SH	P	S	16	4.4/1	70,000	1976
11.	Carborundum Co. Niagara Falls, N.Y.	CAR	RA	S	9	2/1	42,000	1967
12.	Case Western Reserve U. Cleveland, Ohio	FK	Tbd	-	-	Tbd	Tbd	Tbd
13.	Caterpillar Tractor Co. Decatur, Ill.	SH	POL	S	33	4.3/1	150,000	1976
14.	Consolidated Rail Corp. Altoona, Pa.	WF	RA, sa	S	(3)-18	3.5/1	108,000	1978
15.	Delco-Remy-Div. GM Anderson, Ind.	SH	P	S	(3)-9	3/1	24,000	1976
16.	Denver Federal Center Denver, Colo.	ZU	RA	S	9	2.23/1	174,000	1978
17.	E.I. DuPont Co. Cooper R, S.C.	WP	RA, va	S	20	1.9/1	90,000	1977
18.	E.I. DuPont Co. Martinsville, Va.	WP	RA, va	PC	45	1.9/1	203,000	1977
19.	E.I. DuPont Co. New Johnsonville, Tenn.	SH	P	S	(2)-29	4.4/1	130,000	1975
20.	E.I. DuPont Co. Parkersburg, Va.	SH	P	S	(4)-50	4.4/1	221,000	1974
21.	E.I. DuPont Co. Waynesboro, Va.	WP (test unit)	RA, va	PC	76	1.9/1	340,000	1977
22.	Energy Development Co. Hanna, Wyo.	ICA	RA	S	5	2.5/1	24,000	1976
23.	Formica Corp. Evandale, Ohio	WF	RA, sa	S	3	3.38/1	42,000	1978
24.	Hammermill Paper Co. Lockhaven, Pa.	ICA	RA	S	53	2/1	150,000	1976
25.	Hanes Dye and Finishing Winston-Salem, N.C.	DX	P	S	(2)-13	8.3/1	61,000	1975
26.	Harrison Radiator- Division GM Lockport, N.Y.	WP	P	S	30	5/1	139,000	1974

(continued)

TABLE 19 (continued)

	Name/location	Manufacturer	Cleaning mechanism	Boiler firing method	Size $(MW)_e$	A/C*	acfm†	Startup date
27.	Hiram Walker & Sons Peoria, Ill.	Tbd	Tbd	PC	60	Tbd	270,000	1978
28.	Keener Rubber Co. Alliance, Ohio	WF	P	Hdf	100 hp	4.36/1	5,500	1977
29.	Kerr Industries Concord, N.C.	ES (test unit)	Var	S	8	3-14/1	35,000	1974
30.	Kingsley Air Force Base Klamath Falls, Oreg.	SH	P	S	5	5/1	24,000	1976
31.	Long Lake Lumber Co. Spokane, Wash.	MP	P	HF	5	4.5/1	24,000	1973
32.	Lubrizol Corp. Painesville, Ohio	SH	P	OF	8	4.3/1	35,000	1974
33.	Monroe Reformatory Monroe, Wash.	ICA	Sh	S	3	2.8/1	11,000	1976
34.	Pennsylvania Glass Sand Corp. Union, Pa.	FD	P	PC	6	7/1	40,000	1972
35.	Republic Steel Warren, Ohio	WF	RA, sa	PC	35	3.34/1	275,000	1978
36.	Simpson Timber Co. Shelton, Wash.	SH	POL	HF	51	4.3/1	230,000	1976
37.	Sorg Paper Co. Middletown, Ohio	ZU	RA	PC	10	1.8/1	45,000	1972
38.	Uniroyal, Inc. Painesville, Ohio	SH	P	PC	9	2.6/1	42,000	1976
39.	Uniroyal, Inc. Mishawaka, Ind.	Tbd	Tbd	PC	22	Tbd	100,000	1977
40.	University of Illinois Chicago, Ill.	DV	P	OF	8	6/1	35,000	1976
41.	University of Iowa Oakdale, Iowa	ES	Tbd	-	-	Tbd	Tbd	Tbd
42.	University of Minnesota Minneapolis, Minn.	CAR	RA	S	20	2/1	90,000	1976
43.	University of North Carolina Chapel Hill, N.C.	WP	RA	-	(2)-6 each	Tbd	Tbd	1978
44.	University of Notre Dame South Bend, Ind.	WF (test unit)	P	S	1	7/1	3,500	1972
45.	Utah-Idaho Sugar Co. Moses Lake, Wash.	EB	Sh	S	22	2/1	98,000	1976
46.	U.S. Navy Hawthorne, Nev.	ICA	RA	S	21	1.7/1	96,000	1976
47.	U.S. Steel Co. Provo, Utah	WF	RA, sa	PC & gas	(3)-90	3.2/1	~900,000	1977
48.	Westinghouse Electric Richland, Wash.	MP	RA	S	7	2/1	32,000	1976
49.	Westvaco Tyronne, Pa.	WF	RA, sa	S	20	3.26/1	135,000	1979
50.	Witco Chemical Bradford, Pa.	WF	RA, sa	1-S 1-PC	(2)-18	3.17/1	105,000	1978

(continued)

TABLE 19 (continued)

	Name/location	Manu-facturer	Cleaning mecha-nism	Boiler firing method	Size $(MW)_e$	A/C*	acfm†	Startup date
51.	General Motors Corp. Kettering & Norwood, Ohio Three Rivers, Mich. Warren, Ohio	SH	-	7-S	-	-	-	1979
52.	Scott Paper Co. Everett, Wash.	-	-	5-HF	-	-	260,000	1979
53.	Federal Bureau of Prions Fed. Correct. Institution Alderson, W.Va.	ES	-	S	-	2.6/1	16,000	1979
54.	Tennessee State Univ. Nashville, Tenn.	CE	RA	3-coal	-	-	50,000	-
55.	Georgetown Univ. Washington, D.C.	ES	-	FBC	-	5/1	43,000	-
56.	GSA, West Heating Plant Washington, D.C.	RC	P	2-S	-	-	-	1979
57.	Westpoint-Pepperell, Inc. Opelika, Ala.	BS	-	coal	-	-	-	-
58.	U.S. Gypsum Co. Plasterco Plant Saltville, Va.	-	P	3-S	-	-	41,500	-
59.	AVTEX Fibers, Inc. Front Royal, Va.	EB	-	5-coal	-	-	600,000	March 1980
60.	Michigan State Univ.	RC	RA	2-PC	2-60	1.9/1	300,000	1980
61.	3-M Company St. Paul, Minn.	ICA	RA	2-S	2-14	2.2/1	70,000	1978

*A/C as given is in ft/min. To convert to m/min, multiply by 0.3048.

†To convert acfm to m^3/hr, multiply by 1.699

Manufacturers:

AAF - American Air Filter Co.
CAR - Carborundum Co. Pollution Control Div.
DV - DaVair Inc.
DX - Dustex, Sub. Amer. Precision Ind.
EB - Envirotech Corp. Buell Div.
ES - Enviro System Inc.
FD - Fuller Co., Sub GAIX
FK - Flex-Kleen - Sub. R.C.
ICA - Industrial Clean Air Inc.
ME - Menardi-Southern Div., U.S. Filter Corp.
MP - Mikropul Corp., Sub. U.S. Filter Corp.
SH - Standard Havens Inc.
WF - Wheelabrator-Frye Inc.
WP - Joy Mfg. Co Western Precip. Div.
ZU - Zurn Industries, Air Systems Div.
CE - CE Air Preheater
RC - Research-Cottrell
BS - Bahco Systems, Inc.

Symbols:

Hdf - Hand-fired
HF - Hogged fuel
OF - Oil-fired
P - Pulse
PC - Pulverized coal
Pol - Pulse, off-line
RA - Reverse air
RA, sa - Reverse air, shake assist.
RA, va - Reverse air, vibrator assist.
S - Stoker-fired
Sh - Shaker
Sp - Special
Tbd - To be determined
Var - Various
FBC - Fluidized Bed Combustion

8. Gas conditioning and/or fabric conditioning

9. Structural factors, modular, prefabrications

10. Maintenance factors

11. System controls, automation and monitoring

Cleaning methods normally used for coal-fired boilers include reverse air, reverse air with shaker assist, and pulse-jet. Gas-to-cloth ratios are typically 0.61 to 1.2 m/min (2 to 4 ft/min) with some installations operating at 2.4 m/min (8 ft/min) or higher. The trend in the industry has been towards negative pressure or suction baghouses (fan located downstream of the control device that handles cleaned gas) and a modular design to readily adapt to a broad range of gas handling capacities. Fabric conditioning, where used, consists of limestone, dolomite or sometimes fly ash injection to precoat the bags prior to initial operation. Once the bags become coated with a dust filter cake, this practice is discontinued.

There are no unusual operational procedures which would affect system performance other than the deliberate bypassing of the baghouse. The main area for concern is that frequent and thorough maintenance inspections of all system components be a basic part of the operating procedure. Inspection of the bags at regular intervals is most important. Indications of trouble are visible emissions and rapid changes in pressure drop (increase or decrease).

Variations in fuel properties are not as critical as with ESP technology, but sulfur and water content are important from the corrosion and liquid condensation standpoints. It is essential that baghouse temperatures always be maintained above the dewpoint of the gas so that condensation of highly acidic liquid will not occur on the compartment walls and, more importantly, on the filter surface. In the latter case, the problem of severe plugging may drastically reduce gas flow and also cause irreversible bag damage.

Although the users of fabric filtration equipment have been generally satisfied with past equipment performance, more stringent regulations would require solid user-vendor interaction if optimum filtration is to be attained.

In 1978, fabric filters accounted for only about 5 percent of the market for industrial boiler particulate control, whereas an increase to over 10 percent is projected by 1981.[30]

Current research and development under EPA sponsorship includes: assessment of full-scale filter systems on two-stoker-fired boilers; assessment of a full-scale system on a 350-MW utility boiler burning low sulfur coal; assessment of combined SO_x/particulate control with a baghouse; and mathematical/computer modeling of the fabric filtration process.[31]

Additional work is being done in areas concerning new fabric materials and electrostatic effects, all of which will lead to better designs, improved performance and reliability, and longer fabric life.

As with ESP control systems, retrofitting can be difficult because of severe space limitations and, therefore, can result in higher costs for installation. However, the problems are solvable and where such difficulties arise, the main concern will be the overall economic impact.

2.2.2.2 System Performance--

Of the systems listed in Tables 18 and 19, many units are not yet operational or have operated for only brief periods. A summary of performance data and related operating parameters for those facilities for which test data are available is presented in Table 20. Information on the fuel burned, the type of test, and the inlet loading to the baghouse are shown when available. Emission rates given in units other than ng/J (lb/10^6 Btu) were converted to the latter units for uniformity in reporting.

TABLE 20. PERFORMANCE DATA FOR COAL-FIRED UTILITY AND INDUSTRIAL BOILERS CONTROLLED BY FABRIC FILTERS

Source	Fuel analysis			Type of test	Inlet loading (gr/acf or other)	Outlet emission rate reported				% Efficiency
						Given as:			Calculated	
	% S	% Ash	Btu/lb			lb/10^6 Btu or other	gr/acf	gr/scfd	lb/10^6 Btu	
1. Pennsylvania Power & Light[32] Sunbury Station	1.9 (15-35% petroleum coke + anthracite silt + buckwheat anthracite)	23	10,000	EPA-5	~3 gr/scfd	0.0045-0.0058	-	~0.002	-	99.92
2. Colorado-Ute Elec. Assoc.[33] Nucla Station	0.7	14	12,500	EPA-5	~2 gr/scfd	0.01	-	0.0031	-	99.84
3. Pennsylvania Power & Light[34] Holtwood Station	0.7	20-35	8,000	Modified EPA-5	~7^+	0.042	-	-	-	99.91-99.94
4. Nebraska Public Power District[35] Kramer Station	0.4-0.8	4	10,300	EPA-5	0.32	-	0.00966	0.0162	0.0457	96.98 (calculated)
5. Adolph Coors Co.[36] Golden, Colo.	0.4	18-25	8,750	EPA-5	-	7.9-25 lb/hr	-	-	0.027-0.085	-
6. U.S. Steel Co.[37] Provo, Utah	Plant gas (blast furnace, mixed, and natural) 0.55	7.0	13,300	NA	0.53	10.69 lb/hr	0.0013	0.0025	0.01	99.77
7. Caterpillar Tractor Co.[38] Decatur, Ill.	2.9	8-9	-	EPA-5	-	See Table 68			-	-
8. Simpson Timber Co.[38] Shelton, Wash.	Hogged fuel			NA	-	-	-	0.005	0.027	-
9. Kingsley AFB[38] Klamath Falls, Oreg.	0.8	12	-	NA	-	-	-	0.008	0.02	-
10. E.I. DuPont[38] Parkersburg, W. Va.	2.5	7	-	NA	-	-	-	0.007	0.0169	-
11. E.I. DuPont[38] New Johnsonville, Tenn.	3.2	7	-	NA	-	-	-	0.008	0.0188	-
12. Amalgamated Sugar Co.[39] Twin Falls, Idaho	0.85	NA	10,000	EPA-5	-	3.39-30.4 lb/hr	0.004-0.0345	0.007-0.0651	0.012-0.11	-

Note: To convert from Btu/lb to kJ/kg, multiply by 2.326

To convert from lb/10^6 Btu to ng/J, multiply by 430

To convert from lb/hr to kg/hr, multiply by 0.454

To convert from gr/ft^3 to g/m^3, multiply by 2.29

These data, although limited, show emission levels of 1.935 to 47.3 ng/J (0.0045 to 0.11 $lb/10^6$ Btu) and reported efficiencies up to 99.94 percent. The emissions data for sources 8 to 11 were given only as gr/scfd outlet with no other information on the type of test, load level excess air rate or other operating conditions. Therefore, calculated rates in terms of ng/J ($lb/10^6$ Btu) should be treated as rough estimates only.

Recent laboratory studies with fabric filters have demonstrated a strong correlation between outlet concentration and face velocity (air-to-cloth ratio) for a given loading and type of fabric. The relationship, which is presented in Figure 14,[40] indicates that care must be exercised when increasing face velocity to improve system economics. Field pilot studies also show the same effect, Figure 15,[41] although there are some inconsistencies probably due to control problems in field experimentation.

It must also be noted that higher gas velocities can lead to increased filter resistance and hence greater power costs. Additionally, increased cleaning to reduce filter resistance will require increased cleaning energy and may also reduce bag service life. The costs generated by the aforementioned factors will ultimately override the advantage of smaller collector size and less fabric area, leading to an optimum filtration velocity in terms of total annualized cost.

The major factors affecting boilers controlled by fabric filters are additional maintenance requirements, potential corrosion problems, and transient operations. Regular maintenance is particularly important with respect to the bags. Usually, close inspection of the stack for signs of visible emissions and use of pressure sensors and hopper level indicators will forecast potential trouble. Corrosion problems are associated mainly with startups

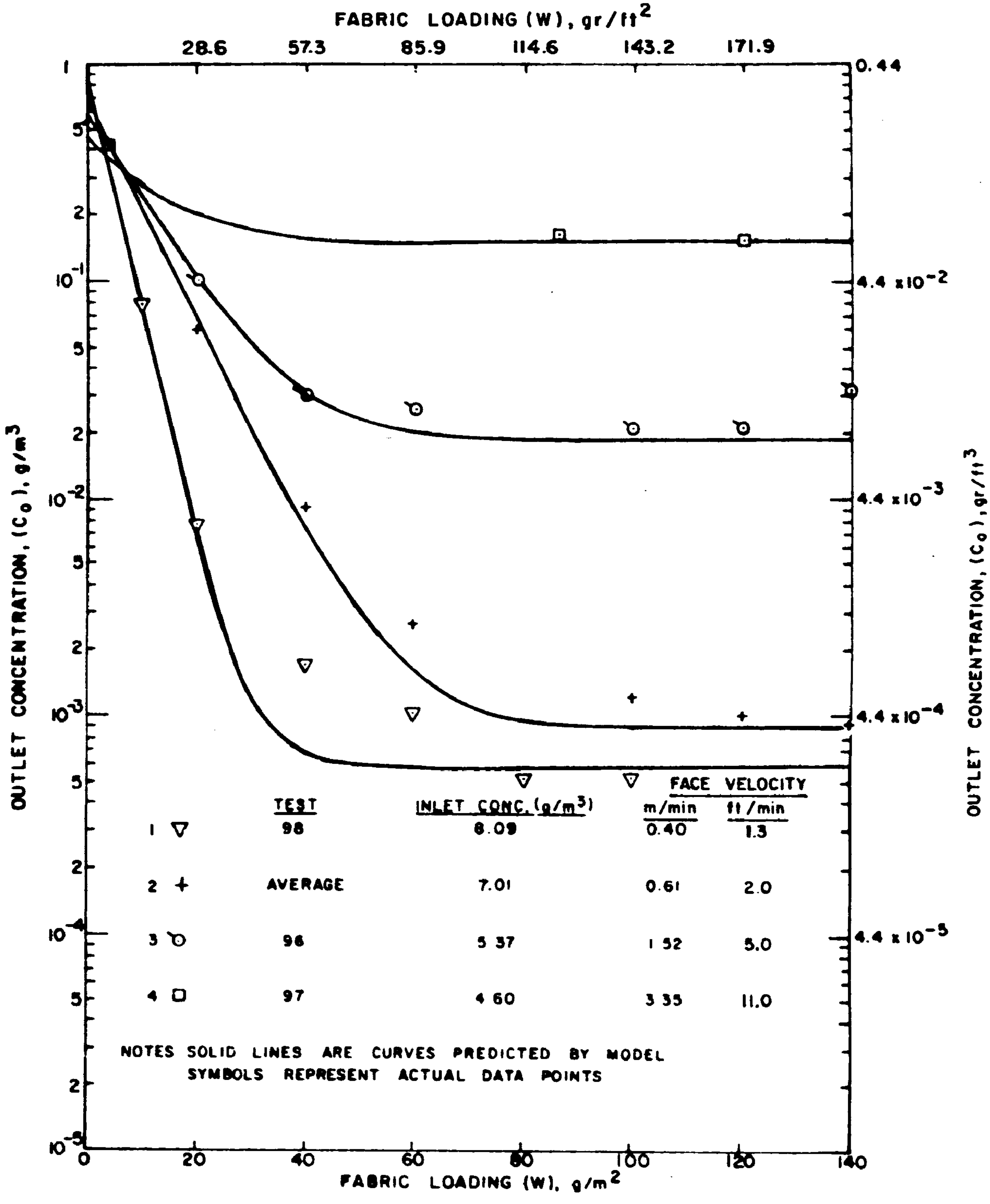

Figure 14. Predicted and observed outlet concentrations for bench scale tests. GCA fly ash and Sunbury fabric.[40]

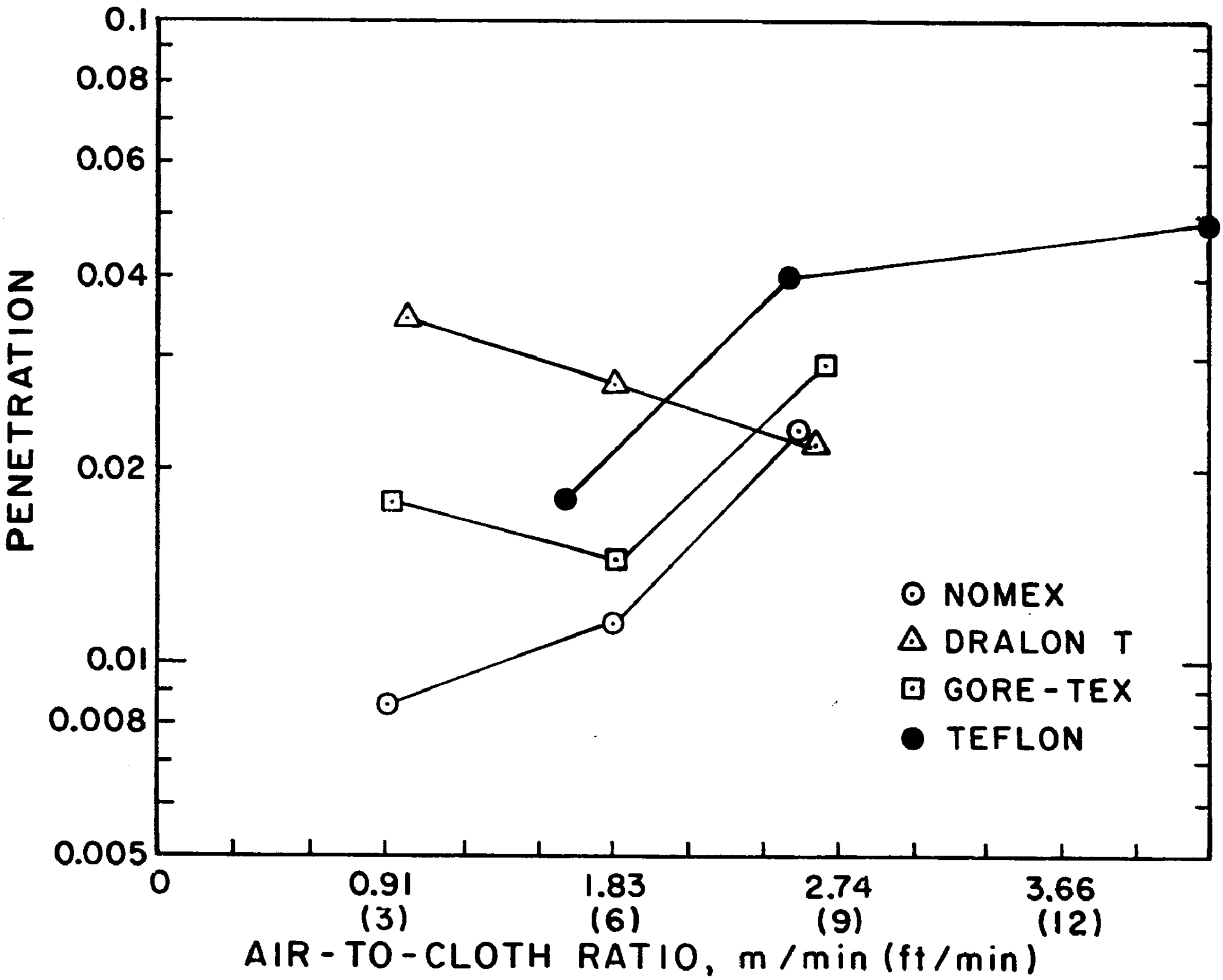

Figure 15. Penetration versus air-to-cloth ratio for different bag materials.[41]

and shutdowns (or fluctuating loads) at which time gas stream temperatures may fall below the acid or moisture dewpoint. Bypassing or preheating the baghouse prior to system startup, continuous gas recirculation during brief shutdowns, and/or sufficient insulation (7.6 cm or 3 inches of mineral wool or fiberglass) will minimize corrosion problems. The above items indicate that operating conditions such as temperature, velocity, pressure, airflow and fan static pressure need to be monitored closely to guarantee effective fabric filtration.

The test data that have been presented are limited, such that there is yet no solid data base to project the likely effective service lives of the fabrics. However, these data do show that low emission levels are achievable for all types of fuels, a major concern of boiler operators. Although vendors will usually guarantee to meet any emission level down to about 0.046 g/scmd (0.02 gr/scfd), they seem to be reluctant to specify emissions in terms of ng/J (lb/10^6 Btu).

Performance with respect to visible emissions is excellent with no visual opacity being the general rule. Where visual emissions do occur, they are usually indicative of system startup or bypass leakage due to a ruptured bag(s). Also, since most emissions are due to gross tears or ruptures in the bags, downstream and upstream particle size distributions are similar.

2.2.3 Wet Scrubbers

2.2.3.1 System Description--

Although collection of particulate matter by scrubbing devices has been ascribed to several capture phenomena, the two most important mechanisms are usually inertial impaction and Brownian diffusion. The former process is responsible for collection of particles greater than about 0.5 μm whereas the latter applies mainly to the smaller size fractions.

Small particles are recovered from the gas stream by direct contact with suspended liquid droplets or by adhesion to the scrubber walls followed be subsequent flushing into a waste disposal system.

Where scrubbing is applied for control of fly ash from combustion processes, the selection is usually confined to several types: gas atomized spray scrubbers such as Venturi and flooded disc scrubbers; fixed-bed absorbers such as sieve tray units; turbulent contact absorbers (TCA) (or moving bed scrubbers); and high pressure spray impingement scrubbers. In those systems where gas temperatures and moisture content are high, the introduction of low temperature sprays produces a condensing atmosphere that enhances supportive collection mechanisms described as flux force/condensation processes by Calvert, et al.[42] Although the above processes almost always contribute to particle collection in all wet scrubbers and gas absorbers, it is very difficult to establish their quantitative roles.

Schematic drawings of the more common scrubber designs are shown in Figure 16.[43]

The main advantages of wet scrubbers are listed below:

- they collect both particulate materials and gases
- they function in wet, corrosive, and/or explosive gas atmospheres
- they may occupy less space than either fabric filter or electrostatic precipitation systems.

The main disadvantages are the following:

- the energy penalties associated with their operation
- possible high effluent opacity and the necessity for reheat
- potential corrosion problems

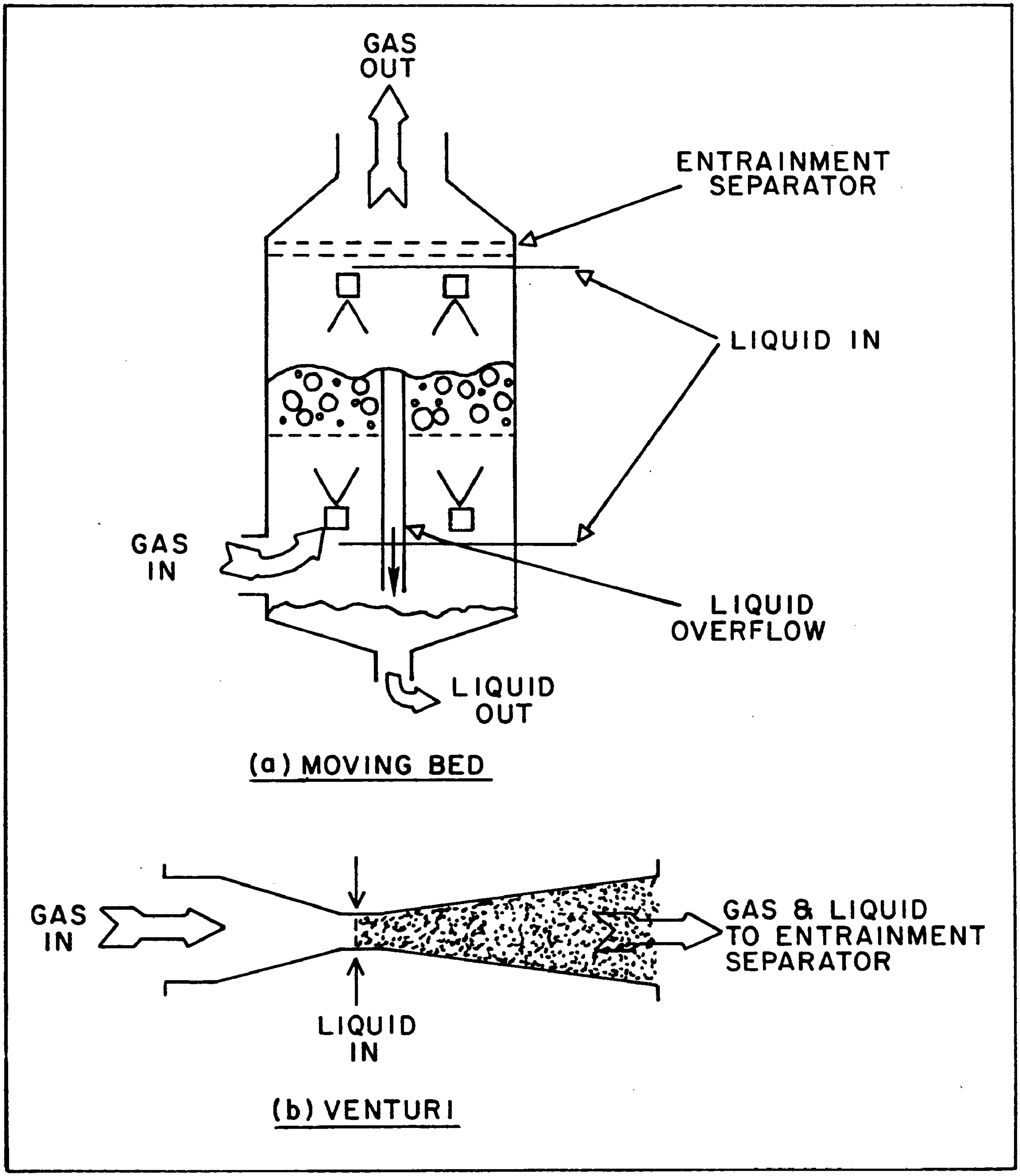

Figure 16. Several types of scrubbers used for particulate control.[43]

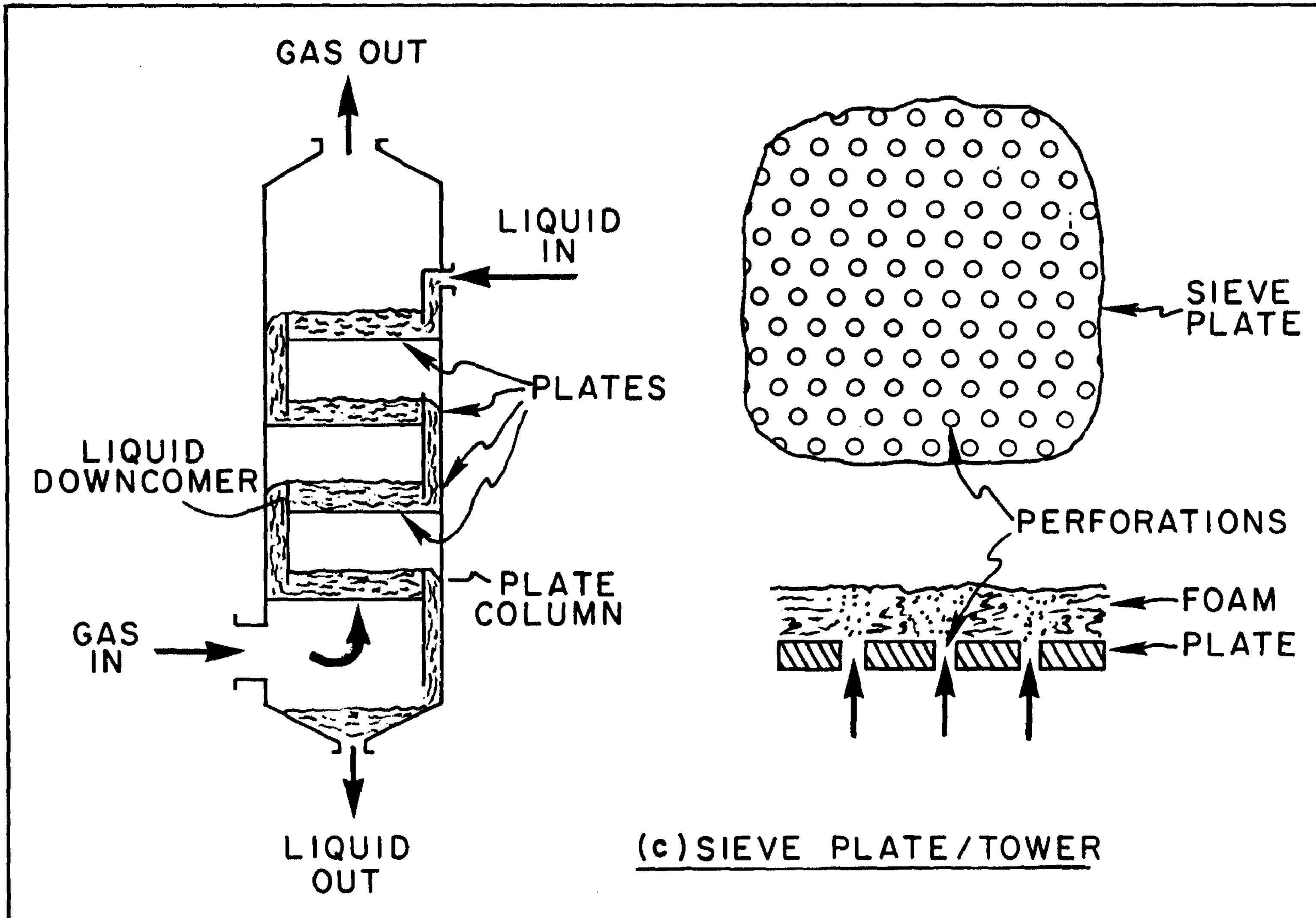

Figure 16 (continued).

- exceptionally high pressure loss to attain equivalent (ESP or filter) efficiencies
- poor efficiency for fine particulates
- the introduction of a water-solid waste disposal problem
- water availability and land requirements may also restrict use of scrubbers in certain geographical areas.

Some of the more important subsystems in a scrubbing system are: liquid pump, piping, sprays and recycle tank, mist eliminator or entrainment separator, provisions for reheat if required (either by steam coils or by direct oil or gas firing) and waste storage and disposal. Consideration must be given to the construction materials used in the basic unit, especially for scrubbers where the slurry is recirculated without benefit of alkaline additives and the pH may fall below 3. For acid environments, 316L stainless steel is inadequate and Fiberglas reinforced polyester or rubber-lined steel are usually used. In the same context, where the particulate scrubber precedes a gas absorber, the fan will generally be located downstream of the absorber so that it will not be subjected to low pH liquid carryover.

When a Venturi scrubber is chosen, it is desirable to install a variable throat system (enabling control of pressure drop) so as to be able to maintain a constant efficiency at varying boiler loads.

Another component that may be required is a liquid cyclone or thickener to remove large particles from recycled liquid streams before reintroduction to spray nozzles to minimize plugging.

Although particulate control by wet scrubbing is a well-established technology, it, like fabric filtration, has only been adopted within the last 10 to 20 years to control fly ash emissions from power boilers. Although the use of wet scrubbers in Great Britain for cleaning boiler flue gases dates back to the 1933 to 1955 era, it was not until the early 1960's that this technology was applied to fossil fuel-fired boilers in the U.S. for combined particulate collection and SO_2 absorption.[44]

Wet scrubber sales for industrial boiler particulate control in 1978, which are estimated at $3 million (5 percent of total nonboiler and industrial boiler applications), are projected to rise to about $12 million (12 percent) in 1982.[45] Related statistics for 1976 were $1 million in sales and 2 percent of total wet scrubber market.

It appears, therefore, that wet scrubbers, like fabric filters, hold a relatively small share of the present market. It is expected that their application may increase over the next several years, depending on sulfur dioxide and particulate removal requirements ultimately required.

Because of the auxiliary equipment required in a scrubbing system (liquid pumps, recirculation tank(s), reheaters, etc.), good maintenance is most important to ensure equipment longevity.

Major research and development efforts are directed at improved geometries for more efficient contacting of liquid and gas streams while reducing energy consumption. However, it is not expected that recent innovations will improve particulate control in the boiler application area. Notwithstanding, some designs that are being used in asphalt concrete plants and metal smelting operations appear to show promise.

Application of wet scrubbers to the industrial boilers under consideration appears limited since these devices are inherently inefficient for submicron particles. However, they have been used on pulverized coal-fired boilers (whose emissions have been shown to range from 10 to 20 μm) with a fair degree of success. (See Table 22.)

Major factors in the design of wet scrubbers for particulate control are gas velocity, gas flow versus spray direction, materials of construction, liquid recirculation, and pH control.

For the venturi scrubbers, gas velocities may range from 61 to 183 m/s (200 to 600 ft/s) while liquid-to-gas ratios (L/G) vary from 1.0 to 2.0 liters/m^3 (8 to 15 gal/1000 ft^3). Pressure drops range from 1.5 to 25 kPa (6 to 100 inches W.C.) depending on application and desired removal efficiency. The liquid is usually introduced in the throat region at right angles or concurrent to gas flow direction.

Impingent plate scrubbers operate at superficial gas velocities of 2 to 3 m/s (8 to 10 ft/s), L/G values of 0.4 to 0.7 liters/m^3 (3 to 5 gal 1000 ft^3) and pressure drops of 0.25 to 2.0 kPa (1 to 8 inches W.C.).

For TCA scrubbers, pressure drops can vary from 2.5 to 5.0 kPa (10 to 20 inches W.C.) while L/G ratios may be as high as 6.7 liters/m^3 (50 gal/1000 ft^3).

The transient, nonsteady state periods of boiler operation are the most critical in terms of control system performance. At these times, temperature, airflow, and particulate loadings show extreme variations which usually affect (adversely) system performance. Once steady state operation is reached, correct settings for liquid injection rate, head loss, and water/solids recirculation rate can be easily maintained. The chance for incorrect settings is a real possibility, given the varying loads often encountered with process steam boilers.

Maintenance is especially critical in wet scrubbing systems due to the corrosive nature of sulfur gases which are absorbed in most scrubbers even when sulfur removal is not the main objective. Since there are more ancillary components with this technology, there are more areas for troublesome operation. Hence, frequent and thorough inspections of equipment are a must.

Variations in fuel properties are important, especially as they affect the resultant particulate loading that reaches the control device. Since scrubber performance has been found to depend on the inlet loading, decreases or increases in ash content will affect the ultimate removal efficiency. (This will be discussed in more detail, subsequently). Variations in ambient conditions affect visible emissions from a wet scrubber in that outside temperature determines the volume of the water vapor plume before dissipation (plume volume being inversely proportional to temperature). Because of water vapor content, smoke reading is difficult on these systems and opacity violations are more difficult to detect.

As discussed previously for ESP and fabric filtration technology, retrofit installations are expected to be more costly and more difficult.

Even though flange-to-flange scrubber modules take up less space than equivalent-sized precipitators and baghouses, the additional equipment required may create space problems in some industrial plants which have limited amounts of accessible area. In such situations, additional piping and duct work will increase capital costs because of the added materials required. Moreover, operating costs will increase because of increased pressure loss in moving the air stream and pumping liquids or slurry.

2.2.3.2 System Performance--

Attempts have been made to relate the performance of a wet scrubber to the pressure drop and liquid-to-gas ratio, L/G. Correlations with the former parameter are indicated in Figure 17.[46]

Because the high velocities and reduced droplet sizes associated with the collection of particles less than 1 μm require increased energy expenditure, the operating pressure loss across Venturi scrubbers, for example, provides an indirect measure of particle collection capability. The relationship is reflected by the data given in Figure 18 in which the ordinate shows the size of the unit density sphere collected at 50 percent efficiency (aerodynamic cut diameter).[47]

A wide range of pressure drops can be required for efficient collection depending on the type of scrubber, the dust characteristics and the liquid-to-gas ratio, L/G. Usually, combustion processes utilizing scrubbers for particulate collection operate in the low-to-moderate energy range of 1.24 to 5.0 kPa (5 to 20 in. W.C.).

Given a coal fly ash whose size parameters are 13 μm for mass median diameter (MMD) and 3.0 for the geometric standard deviation (σ_g), the range of overall weight collection efficiencies have been estimated by GCA as listed in Table 21 for the indicated pressure losses. Gas temperature was assumed to be 149°C (300°F) in the above case for the scrubbing system.

In Table 22, Gronhovd and Sondreal[48] have summarized the performance of various scrubber designs on low-rank U.S. western coals having sulfur contents ranging from 0.5 to 0.8 percent. Generally, particulate removals exceeded 98 percent with incidental sulfur capture of 20 to 40 percent.

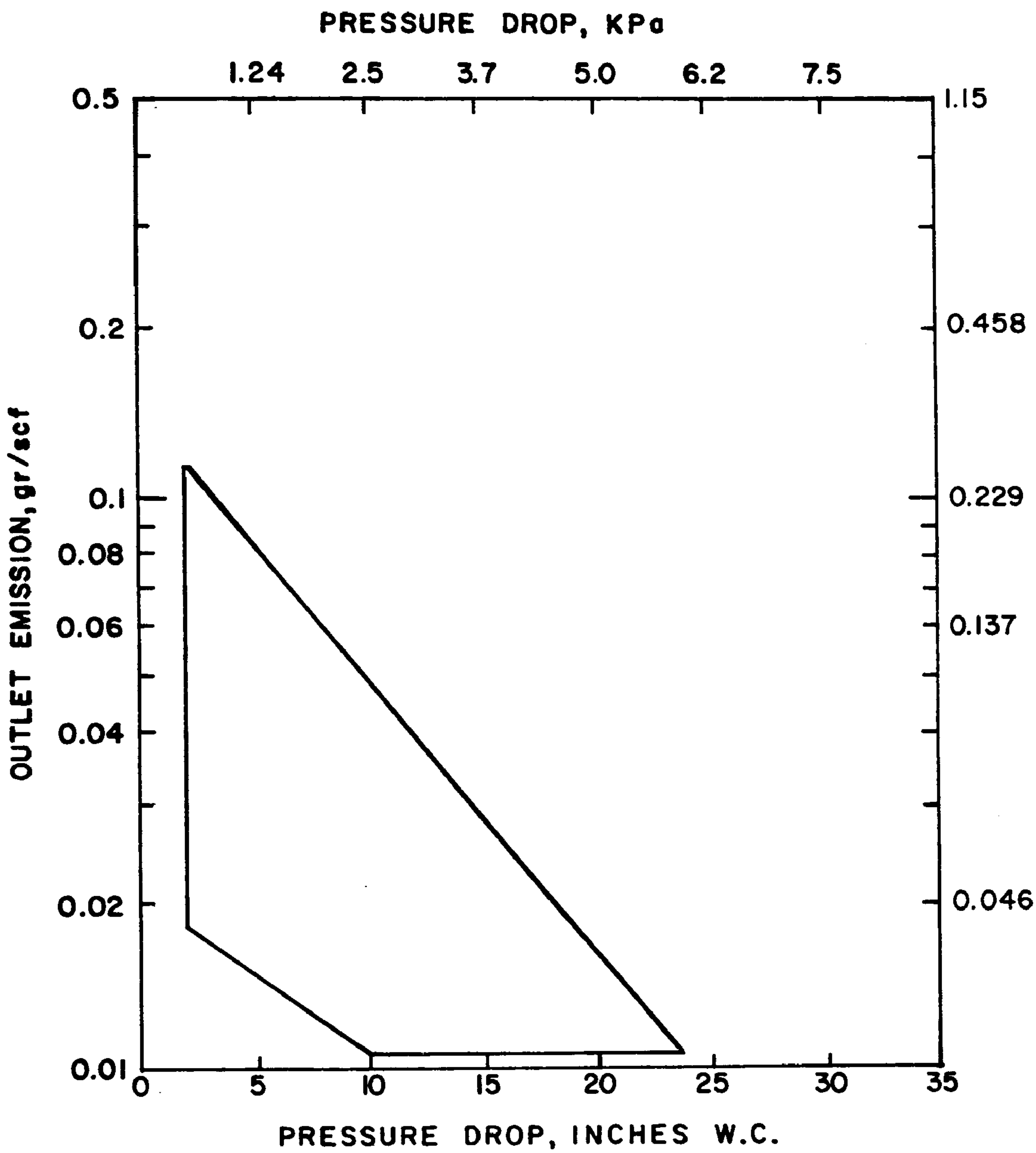

Figure 17. Scrubber particulate performance on coal-fired boilers.[46]

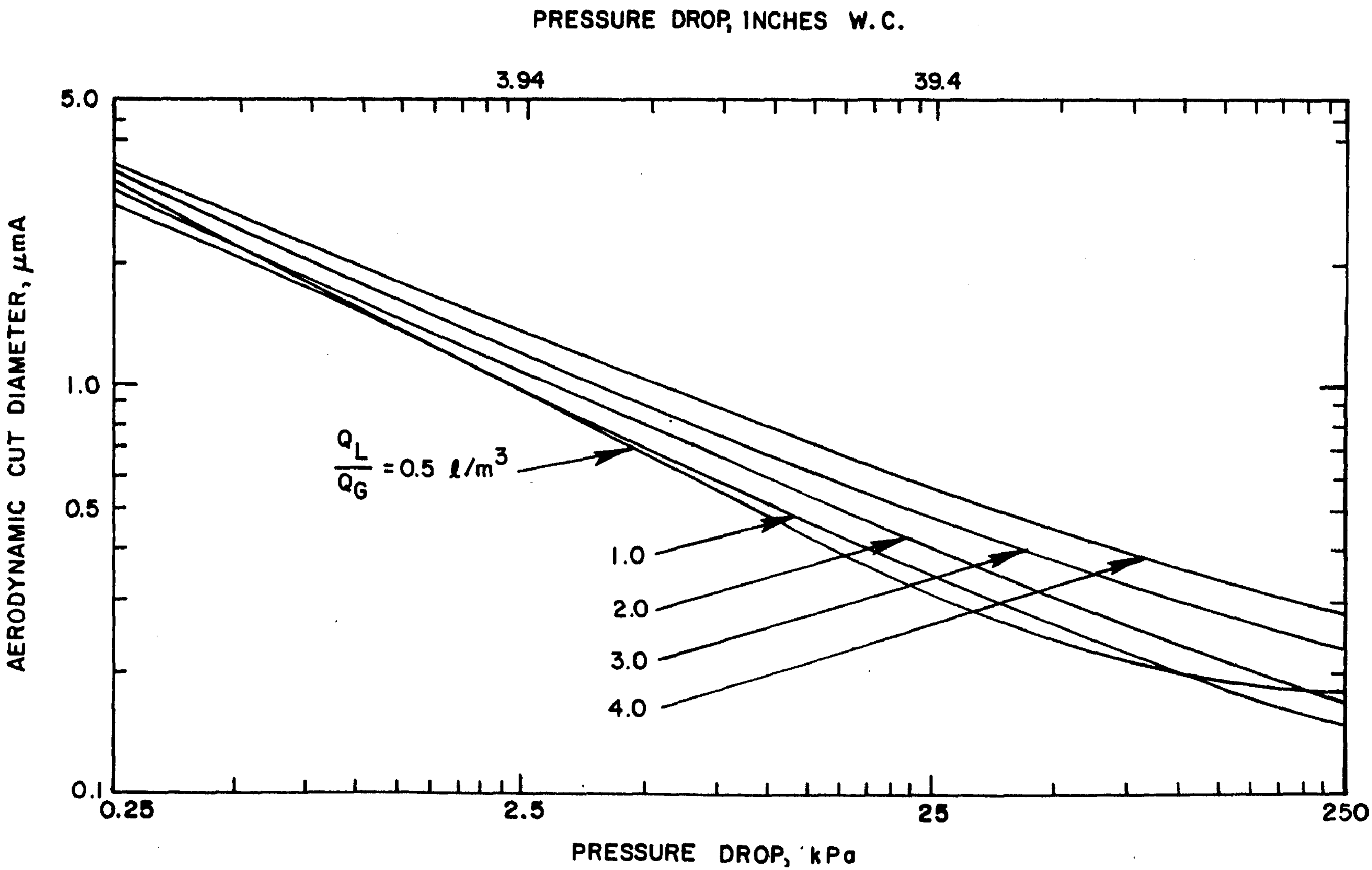

Figure 18. Aerodynamic cut diameter versus pressure drop with liquid-to-gas ratio as parameter.[47]

TABLE 21. OVERALL PARTICULATE COLLECTION EFFICIENCIES FOR VARIOUS PRESSURE DROPS IN A SPRAY SCRUBBER*

Δ p		Percent efficiency (overall)
kPa	(in. H_2O)	
1.24	(5)	88.0 - 94.9
2.5	(10)	91.9 - 97.0
5.0	(20)	94.9 - 98.4
7.5	(30)	96.2 - 98.9

*Dust characteristics: fly ash

MMD = 50% size = 13 μm

$$\sigma_g = \frac{87\% \text{ size}}{50\% \text{ size}} = 3.0$$

Additional performance data were available from a previously cited report for the Edison Electric Institute.[49] These data, showing test results for two western and one eastern power stations, are presented in Table 23. The Venturi scrubber at Pennsylvania Power & Light's Holtwood Station is installed in parallel with a fabric filter and during the performance test the scrubber was handling 59 percent of the flow. An efficiency of 99.4 percent corresponding to a mass emission rate of 55.9 ng/J (0.13 lb/10^6 Btu) was obtained while the Venturi was operated at 1.5 kPa (6.2 inches W.C.). It is important to note that at this particular station, the opacity of emissions ranges from 35 to 40 percent (exclusive of soot-blowing) and is therefore allegedly out of compliance with the state's 20 percent opacity limit. It seems probable that the scrubber is unable to collect the fine particle fraction of the gas stream which could account for 10 to 20 percent of the total particle surface area present.

The other two stations for which scrubber information was available are Valmont and Cherokee of the Public Service Co. of Colorado. Valmont's Unit

TABLE 22. SUMMARY DATA ON PARTICULATE SCRUBBERS OPERATING ON BOILERS BURNING LOW-RANK WESTERN U.S. COALS[48] (1976)

Utility Company	Arizona Public Service Company	Pacific Power and Light Company	Public Service Company of Colorado		Minnesota Power and Light Company		Montana Dakota Utilities
Station Location	Four Corners, Farmington, New Mexico	Dave Johnston, Glenrock, Wyoming	Valmont, Boulder, Colorado	Arapahoe, Denver, Colorado	Clay Boswell, Cohasset, Minnesota	Aurora, Aurora, Minnesota	Sidney, Sidney, Montana
Scrubber startup date	12/71	4/72	11/71	9/73	5/73	6/71	12/75
Reagent	none	none	none	none	none	none	Limestone for pH control
Vendor	Chemico	Chemico	UOP	UOP	Krebs	Krebs	Research-Cottrell
Design and Operating Parameters:							
Scrubber type	venturi	venturi	3-stage TCA	3-stage TCA	high pressure spray	high pressure spray	flooded disk venturi
No. of equipped boilers	3	1	1	1	1	2	1
No. of scrubber modules per boiler	2	3	2	1	1	1	1
Total capacity equipped with scrubbers, MW	575	330	118	112	350	116	50
Reheat	yes	no	yes	yes	no	no	no
Bypass	no	no	yes	yes	no	no	yes
Capital cost, $/kW	52	24	30	41	NA	NA	90
Coal, state, rank	NM subbit	WY subbit	WY subbit	WY subbit	MT subbit	MT subbit	MT lignite
Sulfur in coal, pct	0.7	0.5	0.6	0.6	0.8	0.8	0.7
Ash in coal, pct	22	12	5.2	5.2	9	9	8.5
Calcium oxide in ash, pct	4	20	20	20	11	11	25
L/G, gal/1,000 actual ft^3 *	9	13	50	50	8	8	15-25
ΔP, total inches H_2O †	28	15	10-15	10-15	4	4	13
Open or closed loop	open	intermittent open	open	open	open	open	closed
Water requirement, acre-ft/MW-yr ‡	5.91	2.42	2.88	2.68	4.29	30.2	1.46
Scrubber power consumption, pct of generating capacity	3-4	2.3	5.09	4.02	0.86	0.86	1.2
Inlet dust loading, gr/ft^3 § (g/m^3)	12 (27.5)	4 (9.15)	0.8 (1.83)	0.8 (1.83)	3 (6.86)	2 (4.58)	1.25 (2.86)
Inlet SO_2, ppm, v/v dry	650	500	500	500	800	800	700
Particulate removal	99.2%	99%	97.5%	97.5%	99%	98%	98%
SO_2 removal, pct	30	40	40	40	20	20	NA
Availability, pct	80	NA #	80	20-40	NA	NA	NA

*To convert from gal/1000 aft^3 to liters/am^3, multiply by 0.1337.

†To convert from in. H_2O to kPa, multiply by 0.2488.

‡To convert from acre-ft/MW-yr to m^3/MW-yr, multiply by 1233.

§Volume at one atmosphere and 15.5°C (60°F) for dry gas.

#NA = Data not available.

TABLE 23. PARTICULATE SCRUBBER PERFORMANCE DATA FOR THREE COAL-FIRED BOILERS[49]

Power company and station	Boiler No. size	Scrubber type	Flow rate (acfm)[a]	ΔP (in. H_2O)[b]	Test efficiency (percent)	L/G ratio (gal/1000 aft^3)[c]	Emission rate	
							($lb/10^6$ Btu)[d]	(gr/sft^3)[e]
Penn. Power & Light, Holtwood	No. 17 79 MW	Venturi	229,800	6.2[f] 0.3[g]	99.4	15.4	0.13	0.047
Public Service Co. of Colorado, Valmont	No. 5 166 MW	UOP - TCA[h]	350,000	10-18	97	58.3	0.04	0.02
Cherokee	No. 4 350 MW	UOP - TCA[h]	1.182×10^6	10-18	99.6	55.3	0.04	0.02

[a]To convert from acfm to m^3/hr, multiply by 1.699.

[b]To convert from in. H_2O to kPa, multiply by 0.2488.

[c]To convert from gal/1000 aft^3 to liters/am^3, multiply by 0.1337.

[d]To convert from $lb/10^6$ Btu to ng/J, multiply by 430.

[e]To convert from gr/sft^3 to g/sm^3, multiply by 2.29.

[f]Across venturi throat.

[g]Across mist eliminator.

[h]Turbulent contact absorber.

No. 5 has a turbulent contact absorber (TCA) in parallel with a "cold" Electrostatic precipitator while Cherokee's Unit No. 4 has the same arrangement. Both units have achieved an emission rate of 17.2 ng/J (0.04 lb/10^6 Btu) while operating at 2.5 to 4.5 kPa (10 to 18 inches W.C.).

In addition to these data, a survey was made of 16 flue gas desulfurization units, because of the limited use of scrubbers in combustion applications for particulate collection alone. These data are presented in Table 24.[50-65] It should be noted that all values are actual measurements except for inlet loadings which were calculated based on the heating value and ash content of the coal and an assumed 80 percent ash entrainment in the flue gas. These data are displayed in Figure 19.

As expected, a strong correlation is evidenced between penetration and inlet concentration, despite the fact that the data point pairs also reflect significant variations in L/G ratio and operating pressure loss (Table 24). For example, one expects to see increased particle collection whenever the L/G value or the collection resistance increases.

The most important conclusion to be drawn from Figure 19 is that scrubber weight efficiencies are high (and penetrations low) when there is no upstream precleaning device in the system. Basically, Figure 19 states that scrubber efficiencies are strongly dependent on inlet loading such that it is extremely risky to assume that high, ~99 percent collection, is routinely attainable. The increase in efficiency with loading is attributed to the increased chances for particle-to-particle and particle-to-water droplet collisions when the concentration of the particles in the gas stream increases.

In summary, the scrubber performance data presented bear out the following important relationships:

TABLE 24. WET SCRUBBER (FGD) PERFORMANCE FOR PARTICULATE CONTROL[50-65]

Power station	Scrubber description			Inlet concentration‡		Outlet concentration		Scrubber efficiency percent
	Type	L/G ratio* (gal/1000 ft^3)	System resistance (in. water)†	$lb/10^6$ Btu§	gr/sft^3#	$lb/10^6$ Btu§	gr/sft^3#	
1. Reid Gardner Nevada Power Co.[50]	Venturi and sieve tray	10 (venturi)	20 - 25	1.36	0.3 - 0.6	0.05	0.02	95.6-96.3
2. Mohave So. Calif. Edison[51]	Four-stage TCA absorber	-	-	0.145	0.07	0.0026	-	98.2
3. Will County[52] Commonwealth Edison	Venturi and two-stage sieve tray scrubber	34 (varies with load)	25	0.85	-	0.16-0.19	-	78-81
4. Hawthorne Kansas City Power and Light[53]	Marble bed	-	10 - 12	9.1	-	0.18	-	98.8
5. La Cygne Kansas City Power and Light[54]	Venturi and two-stage sieve tray	33	21 - 24	21.2	-	0.15	-	99.3
6. Lawrence Kansas City Power and Light[55]	Venturi and marble bed absorber	20 (venturi) 30 (tower)	12	7.85	3.0	0.063	0.025	99.2
7. Paddy's Run Louisville Gas and Electric[56]	Marble bed two-stage	38	16	0.328	0.2 - 0.4	0.033	0.027-0.035	90.0
8. Cane Run Louisville Gas and Electric[57]	TCA absorber and spray tower	50 - 60	11	0.12	0.08-0.09	0.028	0.02	76.5
9. Phillips Duquesne Light[58]	Venturi one-stage Venturi three-stage (four parallel modules)	30 - 70	10 - 12	3.2	-	0.046	-	98.5
10. Elrama Duquesne Light[59]	Venturi	30 - 50	10 - 12	12.8	-	0.02-0.07	-	99.4-99.8
11. Cholla Arizona Public Service[60]	Flooded disc scrubber and absorber	49	12	2.4	2.0-2.5	0.027	0.008-0.01	98.9
12. Colstrip Montana Power[61]	Venturi and spray tower	15 (venturi) 18 (tower)	17	6.88	-	0.033	-	99.5

(continued)

TABLE 24 (continued)

Power station	Scrubber description: Type	Scrubber description: L/G ratio* (gal/1000 ft^3)	Scrubber description: System resistance† (in. water)	Inlet concentration‡: $lb/10^6$ Btu§	Inlet concentration‡: gr/sft^3#	Outlet concentration: $lb/10^6$ Btu§	Outlet concentration: gr/sft^3#	Scrubber efficiency percent
13. Sherburne Northern States Power[62]	Venturi and marble bed	27	22 - 25	8.6	4.0 (design estimate)	0.078	< 0.04	99.1
14. Widows Creek Tennessee Valley Authority[63]	Venturi and marble bed	50	30	10.0	5.6 (design estimate)	0.128	-	98.7
15. South West Springfield City Utilities[64]	TCA absorber	60	13	0.022	0.01	0.017	-	23.0
16. Green River[65] Kentucky Utilities	Venturi and TCA absorber	35	9.2-12.2	1.87	-	0.14	-	92.5

*To convert from gal/1000 ft^3 to liters/am^3, multiply by 0.1337.

†To convert from inches water to kPa, multiply by 0.2488.

‡Inlet concentration based on heating value and ash content of coal and an assumed 80 percent ash entrainment in flue gas.

§To convert from $lb/10^6$ Btu to ng/J, multiply by 430.

#To convert from gr/sft^3 to g/sm^3, multiply by 2.29.

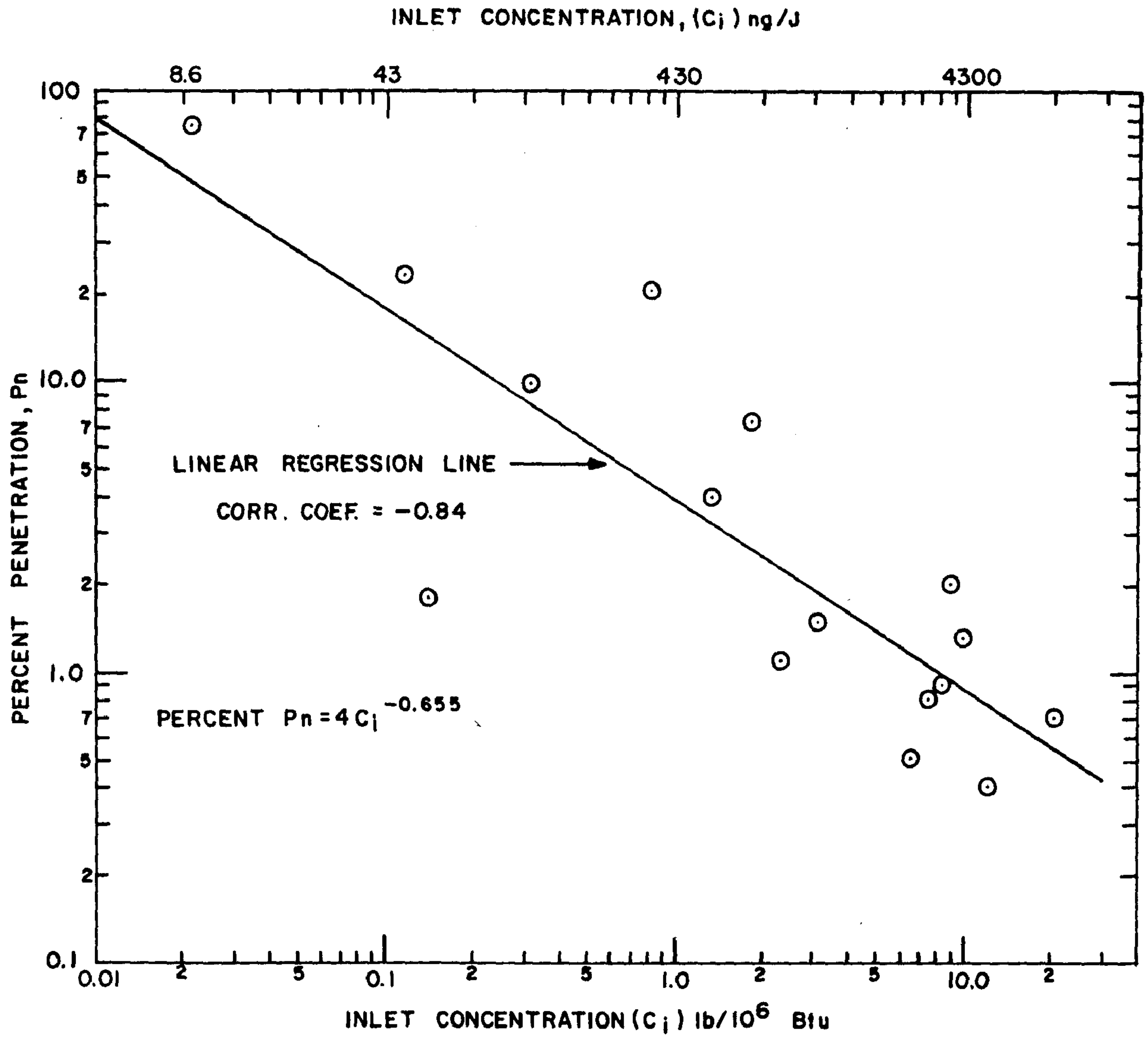

Figure 19. Variations in fly ash penetration with inlet concentration for 16 FGD systems presented in Table 24.

1. Emission rate is strongly dependent on fly ash loading to the scrubber
2. High pressure drops are required to capture submicron particles
3. Opacity is difficult to predict or measure and in some cases may actually be increased by scrubbing systems.

Boiler deratings are sometimes necessary to operate scrubbers because of their high energy consumption. On large utility boilers, this can amount to as much as 5 to 10 percent of rated capacity. Corrosion is certainly possible in particulate scrubbers because of the low pH of recirculating water streams. Thus, rubber-lined pumps and/or fiberglass reinforced polyester materials of construction are often required.

As with the other control technologies, much of the available performance data are from the utility sector (pulverized coal burning installations). Although there could be an advantage with the smaller size industrial units with respect to fewer gas flow distribution problems with a scrubbing tower, the relative cost of the apparatus might be greater because of the larger fraction of the total cost borne by the instrumentation and special maintenance needed to guarantee effective performance.

Again, vendor guarantees are site specific depending on operating flow rate ranges, fuel properties, and local emission codes.

2.2.4 Mechanical Collectors (Multitube Cyclones)

2.2.4.1 System Description--

Multitube cyclones, which represented the most common type of inertial collector used for fly ash collection before stricter emission regulations were enacted, depend upon centrifugal forces (i.e., inertial impaction) for particle removal. They consist of a number of small-diameter cyclones (~5 to 30.5 cm diameter) (~2 to 12 inch diameter) operating in parallel and having a common gas inlet and outlet. The flow pattern differs from that in a conventional cyclone in that the gas, instead of entering tangentially to initiate the swirling action, makes an axial approach to the top of the collecting tube wherein a stationary "spin" vane positioned in its path imparts a rotational motion to the gas. Figure 20 illustrates a typical multitube cyclone along with a view of a single tube.

The only supplemental equipment required for this relatively simple inertial design are dust hopper level indicators, vibrators and/or heaters and an ash conveying and removal system.

Fly ash collection by multitube cyclones is a well-established technology that has been applied for many years on all types of coal-fired industrial and utility boilers. However, comparative sales for 1974 and 1975, 24.5 and 17.3 million dollars,[66] respectively, indicate that because of efficiency limitations they now function mainly as precleaning devices.

In general, users of inertial collection have been quite satisfied with their operation (mostly as precleaners) primarily because of their minimal maintenance requirement.

Major R&D efforts for mechanical collectors have been directed at enhancing the gas spin properties through the use of specially-shaped stationary vanes and the introduction of secondary air to minimize dust contact with the wall of the collector in the inlet region of the unit. If successful, the need for abrasion resistant materials or extra heavy construction can be partially eliminated. However, it is not expected that significant improvements can be made in overall collection efficiency for the fine particulate emissions from pulverized coal systems, for example.

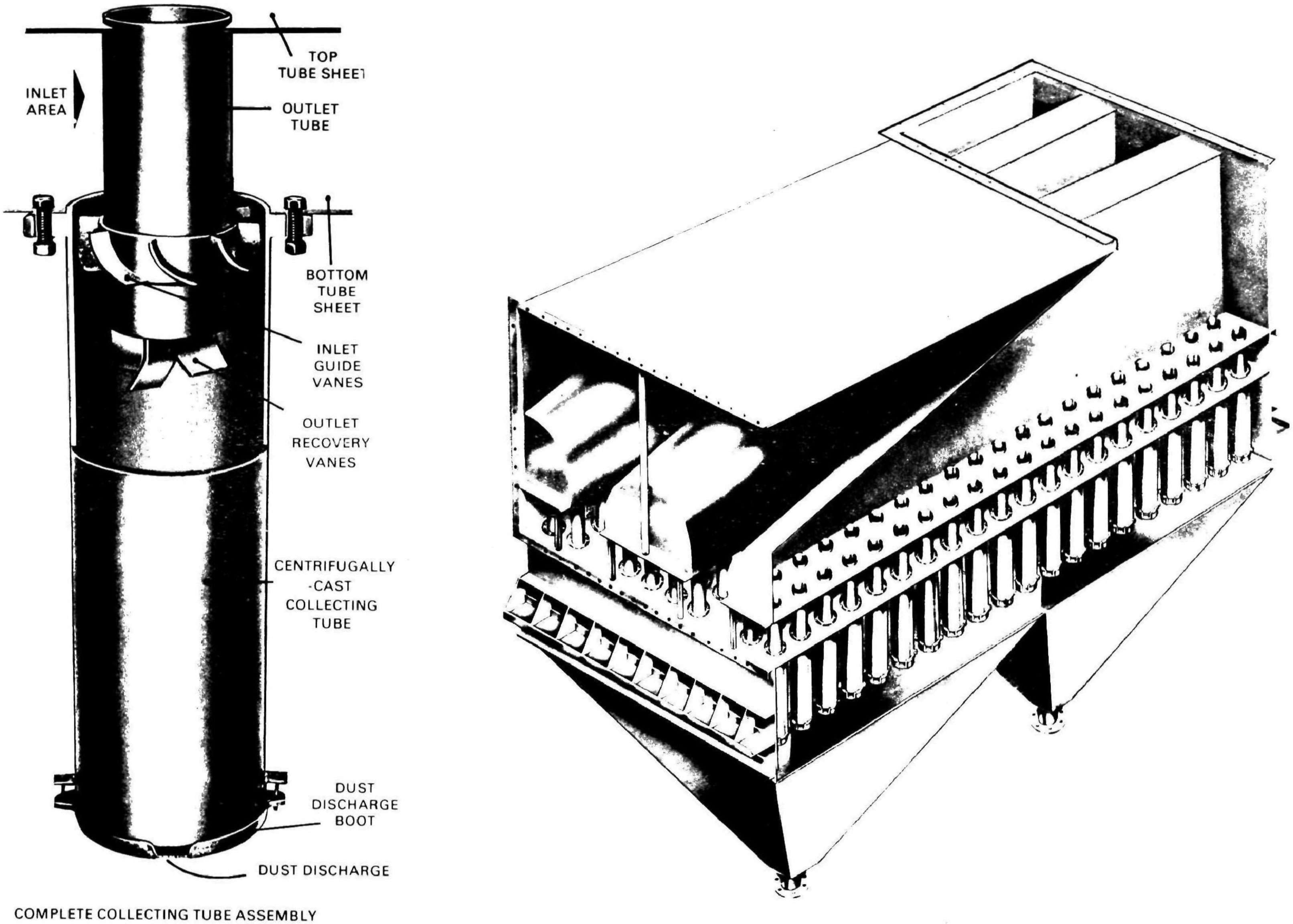

Figure 20. Multitube cyclone and exploded view of a single tube (courtesy of Zurn Industries).

The most critical design parameters for a cyclone collector are the inlet gas velocity, the diameter of the tubes, the number and angle of axial vanes, and the construction materials. Most multitube cyclones are axial-gas entry units designed for gas velocities of 25.4 to 35.6 m/sec (5,000 to 7,000 ft/min) in the entry vane region.[67] Such high velocities require the use of hard alloy materials for the vanes (gray or white iron or chromehard) to minimize vane erosion. Particle collection efficiency for most cyclonic devices varies inversely with the diameter of the collecting tube which governs the gas stream radius of curvature. A reduction in tube diameter increases the radial force acting upon the particles so that their transit to the wall region is accelerated.

The main considerations in evaluating construction materials are:

- Gas temperature
- Abrasiveness of dust particles
- Corrosiveness of gas stream

In addition to the above factors during normal operation, transient conditions such as startup, shutdown, or emergency upsets must be anticipated in the design. Moisture or sulfuric acid condensation is most important in coal-fired systems since fly ash can become very sticky if cooled to the point where condensation takes place. Some preventive measures to alleviate this problem are:

- Preheating the system before startup
- Continuing hot gas airflow after shutdown until the system has been completely flushed of dust and humid gas
- Insulating duct work, cyclone body, and hopper
- Providing artificial heating of the hopper by electric heating or steam tracing prior to insulation application.

There are no specific operational procedures related to the boiler/control device system that would severely hamper system performance other than the transient moisture condition mentioned previously. An attractive feature of most inertial devices is that the operating pressure loss is nearly independent of inlet dust loading as it is with electrostatic precipitators. As with other control devices, maintenance is very important although the lack of moving parts significantly reduces the necessity for detailed full-time maintenance inspections. However, it is important that cyclone pressure loss be accurately monitored so that any tendency to plug can be signaled at once by an appropriate alarm system.

Variations in fuel properties are not critical unless coal-sulfur content changes appreciably from that specified when the control equipment was designed and provisions have not been taken to adequately insulate the unit or to use the proper construction materials.

Retrofit installations in the mechanical collector category will probably be nonexistent simply because it is highly unlikely that any practical design changes could be made that would enable the devices to meet any future stringent emission requirements.

In some cases it has been found more practical to leave in place the existing cyclone units and simply append in series the necessary high efficiency collectors such as fabric filters or ESP systems. In has occasionally been necessary, however, to remove or alter the multiclone tubes so that pressure loss through the device could be lowered sufficiently to meet draft fan capabilities.

The addition of high efficiency equipment may not be possible in many situations due to space limitations. Hence, removal of the inertial device may be necessary. An attempt to operate in very cramped quarters (leaving the multicyclone in place) could also disturb the gas flow pattern into the high efficiency collector, which would be particularly critical in the case of an electrostatic precipitator. An example of a case where the control system could not be retrofitted would be an installation having a stack on the roof with a very short breeching between boiler and stack and a roof construction incapable of bearing added weight. Obviously, there are many possible field configurations where the addition of a supplemental control device would severely effect overall system performance because of poor gas flow distribution.

2.2.4.2 System Performance--

The performance of any mechanical collection system is primarily a function of the aerosol particle size. Many types of "grade" efficiency curves are available such as the curves shown in Figures 21 and 22. Figure 21 illustrates comparative collection efficiencies for two axial-entry cyclones with diameters of 15.2 and 30.5 cm (6 and 12 inches), respectively, as a function of percent of dust under 10 μm.[68] If, for example, one considers a pulverized coal unit with approximately 50 percent of the fly ash less than 10 μm, then efficiencies of about 85 and 73 percent would be expected for these two cyclones, respectively. Figure 22 shows estimated efficiencies as a function of particle size.[69] If the size distribution is available for the inlet dust, the overall collector efficiency may be estimated from Figure 22. Both of these curves appear to be somewhat optimistic in terms of collection of particles 10 μm or less based upon available performance data. Current performance data for mechanical collectors are limited since these devices are often used in conjunction (series) with another control device in which only the overall efficiencies are given. Some test data were available, however, from a previous EPA-sponsored program, Table 25.[70,71] Although

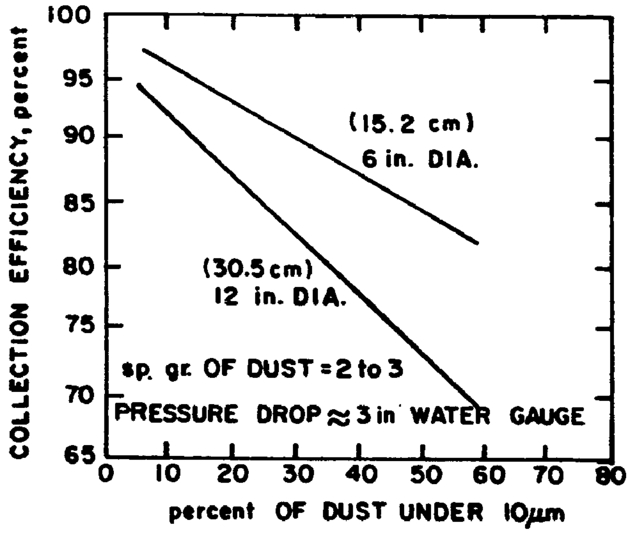

Figure 21. Typical overall collection efficiency of axial-entry cyclones.[68]

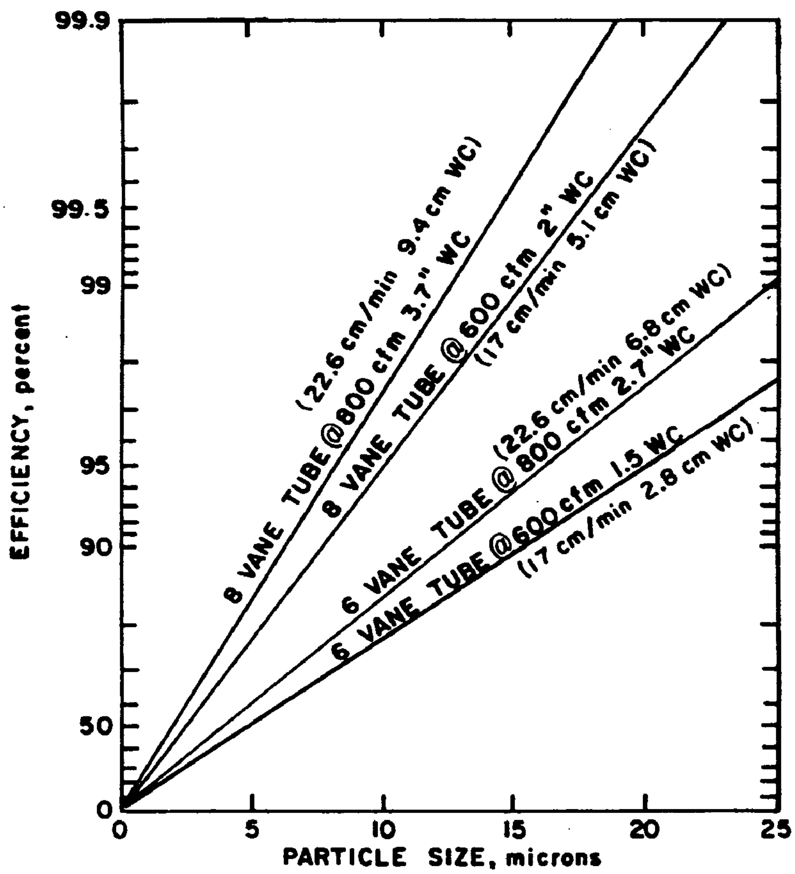

Figure 22. Efficiency versus particle size for various multicyclone systems.[69]

tests 20/21 showed the lowest emission rate, there were two 180° bends in the system in addition to the multitube cyclone which probably accounted for significant dropout of material. As can be seen from these data, emission rates via this control technology are too high to meet the intermediate or stringent emission control levels.

It should be noted that most data are based on stoker firing which usually produces a coarser fly ash than that generated by pulverized coal. (See Table 13.)

The test data presented in Table 25 are predominantly for small utility boilers (~73 MW or 250 × 10^6 But/hr heat input) where mass loadings would be slightly lower than encountered with industrial coal-fired units because of firing method, method of combustion regulation and variations in load level.

TABLE 25. PERFORMANCE DATA FOR COAL-FIRED BOILERS EQUIPPED WITH MECHANICAL COLLECTORS.[70,71]

Test/location	Boiler No.	Furnace type	Steam load* (10^3 lb/hr)	Emission rate† (lb/10^6 Btu)
18/11	1	spreader stoker water tube	110	2.83
20/21	3	spreader stoker water tube	63	0.1915
26/12	24	pulverized water tube	181	0.9931
27/14	1	spreader stoker water tube	120	2.016
28/14	4	spreader stoker water tube	162	0.339
134/30	-	spreader stoker	82	3.05
165/35	-	chain grate	104	0.31

*To convert from lb/hr to kg/s, multiply by 1.26 × 10^{-4}.

†To convert from lb/10^6 Btu to ng/J, multiply by 430.

Pressure drops through mechanical collectors are on the order of 0.75 to 1.5 kPa (3 to 6 inches W.C.) and boiler deratings are not required. Other potential impacts on boiler operation such as corrosion, startup and shutdown, and additional maintenance requirements, have been discussed previously.

Since the difference in inlet concentration is not expected to exert any significant effect on efficiency per se, one should expect to see proportionately higher emissions with industrial boilers. On the other hand, efficiency data from utilities sources can probably be translated directly provided that monitoring and maintenance regimens are similar.

2.3 CONTROLS FOR OIL-FIRED BOILERS

2.3.1 Electrostatic Precipitation

2.3.1.1 System Description--

Because detailed design parameters, subsystems, development status, maintenance aspects and other relevant criteria have been discussed previously in subsection 2.2, only those items which are peculiar to oil-fired systems will be analyzed herein.

Although applications of ESP technology to oil-fired boilers are limited, there are facilities utilizing ESP systems, most of which were designed originally to collect coal fly ash. Boilers now firing oil which formerly burned coal, have employed the use of existing precipitators, sometimes with little or no modification.

Precipitators employed for service on oil-fired systems would utilize special systems for periodic removal of any sticky, tar-like ash deposits from the collecting plates. These deposits can develop because of the hygroscopic character of the oil fly ash.[72] If the oil ash is allowed to accumulate on cool surfaces where condensation and moisture absorption can take place, they may be a potential cause of arcing and short circuiting. Locating the precipitator upstream of the air heater (if one exists) is one possible means of maintaining all collector (and electrode) surfaces at high enough temperatures to minimize ash buildup on high tension wires, insulators and in the dust hoppers.

The carbonaceous content of fuel oil results in a lowered resistivity level for the ash, roughly 10^7 to 10^9 ohm-cm. Occasionally, the solids are so conductive that they fail to hold a charge and therefore are easily reentrained in the gas stream. The above factors combined with the extremely fine size of oil particulate emissions (generally less than 2 μm) can make efficient collection by electrostatic precipitation very difficult. It should be noted that the sulfur content of the oil and the stack gas temperature have little impact on resistivity relative to the changes caused by the carbonaceous material.[73]

Due to the above-mentioned problems, maintenance is very critical, especially because the high combustible content of oil-fired particulates may present a potential fire hazard in the collection hoppers. Steam quenching or fly ash reinjection may remedy this situation.

2.3.1.2 System Performance--

The collection efficiency of precipitators on oil-fired boilers can vary from 45 to 90 percent.[74] An ESP unit originally designed for coal and subsequently used for collection on an oil burning unit with no modifications may only provide an efficiency of about 50 percent. Table 26 summarizes typical test data for oil-fired boilers controlled by ESP technology.[75] When upstream concentration measurements were made, the computed efficiencies ranged from 16 to 71 percent. No supplemental data were available relative

TABLE 26. OIL-FIRED COMBUSTION SYSTEMS CONTROLLED WITH ELECTROSTATIC PRECIPITATORS[75]

Company	Boiler number/capacity (MW)	% S	% Ash	Additive used	Fuel consumption rate (gal/hr)[*]	Control efficiency (%)	Particulate emission rate ($lb/10^6$ Btu)[†]
1. Polaroid Corp.	1/10	0.7	-	No	390	40	0.055
New Bedford	2/10	0.7	-	No	340	51	0.070
2. Boston Edison	3/48	2.4		Yes	3,600	38	0.113
Mystic Station[‡]	3/48	2.4		No	3,600	57	0.150
	3/48	2.4		Yes	3,600	71	0.033
	3/48	2.4		No	3,600	34	0.148
	3/48	2.3		Yes	3,600	-	0.244
	3/48	2.3		Yes	3,600	-	0.154
	3/48	2.3		No	3,600	-	0.154
3. Hartford Electric Light Co.	2/119	1.95	0.09	Yes	7,800	-	0.070
Middletown Station	2/117	1.86	0.07	Yes	7,800	-	0.057
	2/119	1.79	0.07	Yes	7,800	-	0.067
4. United Illuminating Co.	3/406	1.80	0.08	Yes	26,000	-	0.150
Bridgeport Harbor[§]	3/405	1.77	0.09	Yes	26,000	-	0.126
5. Consolidated Edison	30/600	0.3	0.02	No	57,000	16	0.017
Ravenswood[‡]							
Astoria[‡]	50/320	0.3	-	No	19,000	51	0.008
	30/350	0.37	-	No	19,000	54	0.012
	40/355	0.3	-	No	19,000	40	0.012
	50/385	0.37	-	No	19,000	45	0.012

[*] To convert gal/hr to liters/hr, multiply by 3.785.

[†] To convert $lb/10^6$ Btu to ng/J, multiply by 430.

[‡] ESP originally designed for coal.

[§] ESP originally designed for coal, later modified for oil.

to precipitator plate area (SCA) or "hot" or "cold" installation. It is, therefore, difficult to draw any specific conclusions from these findings.

2.3.2 Fabric Filtration

2.3.2.1 System Description--

Control of particulate emissions from oil-fired units by this technology is extremely rare. The hygroscopic character of the uncontrolled fly ash mentioned previously has the potential to plug fabrics and cause serious, irreparable damage. Blinding, as it is called, can occur when excessive dust is irreversibly retained within the fabric pores such that gas flow resistance rises to prohibitively high levels.

Since baghouses require fabric lives of 2 or more years to be competitive with precipitators, anything which will adversely affect a fabric service life would most likely eliminate filtration as a candidate control technology.

2.3.2.2 System Performance--

One facility which has employed this technology is the Alamitos Generating Station of Southern California Edison Company.[76] A full-scale baghouse designed to treat all the flue gas from Unit No. 3 (320 MW_e) was placed in service in 1965 and was arranged in a circular fashion around the stack. This unit fired 69,916 kg/hr (154,000 lb/hr) of high viscosity residual oil at full load. Average ash and sulfur contents were 0.06 and 1.6 percent, respectively. Gas flow at full load was 1.39×10^6 m^3/hr (820,000 acfm) at 126°C (258°F) when firing oil (the boiler is also capable of firing natural gas). Gas-to-cloth ratio under these conditions was 1.7/1-m/min (5.7/1-ft/min) with all 12 compartments in service and 2.0/1-m/min (6.5/1-ft/min) with one compartment down for cleaning. Dampers were provided to permit bypassing of the filterhouse when natural gas is the fuel. During startup of this unit, an alkaline additive was injected into the gas stream at the air heater outlet which served to neutralize sulfur trioxide (SO_3) in the flue gas and to form a filter cake on the bag surfaces. Major problems associated with this installation were:

1. Fabric deterioration due to flue gas in-leakage when the bypass system was used
2. High system pressure drop and uneven flow distribution (Δ P of 2.4 kPa (9.5 inches W.C.) were recorded)
3. Problems with ash-conveying.

Although extensive modifications have resulted in improvements in operation, maintenance, and bag life and the stack opacity was very low, the baghouse is presently on a standby basis because of gas firing.

Two other installations which have employed fabric filtration on oil-fired units are the Lubrizol Corp. in Painesville, Ohio and the University of Illinois in Chicago. (See Table 19.) The Lubrizol installation which is used with an 8 MW, 59,465 m^3/hr (35,000 acfm) system with Teflon fabric and pulse cleaning went on line in 1974. The University of Illinois filter was installed in 1976, used glass fabric, and was a similarly-sized unit.

Recent data from Lubrizol Corporation have indicated that stack test data have been obtained but are unavailable. The source has indicated that the installation is very atypical (it is similar to a waste incinerator) and they would not be willing to provide information on its success or lack of success.

With regard to the University of Illinois, they have switched from oil to natural gas and have taken the baghouse out of service.

2.3.3 Wet Scrubbing

2.3.3.1 System Description--

Since the emissions from oil-fired boilers are predominantly < 2 μm, the use of scrubbers for particulate control is limited. However, these devices could theoretically be used to control acid smut emissions or smoke and carbon emissions during soot-blowing operations. (Sootblowing in industrial boilers is usually done every 8 hours for durations of 6 minutes or less. Simultaneous cleaning of all heat transfer surfaces during these intervals results in coarse particle emissions (~200 μm) due to the reentrainment of solid deposits from air preheater surfaces.) It would not be practical, however, to install scrubbers solely for control of soot-blowing operations.

2.3.3.2 System Performance--

Test data were available from the Mystic Station of the Boston Edison Co. which had previously employed a scrubber utilizing magnesium oxide for SO_2 control, Table 27.[77] In tests 1, 2, and 4, some of the stack gas bypassed the scrubber so that the control device's design capacity would not be exceeded. In test 3, the scrubber was handling the system's full flow. This scrubbing system, which was designed for SO_2 removal only, has since been dismantled. Therefore, these results should not be interpreted as being typical of scrubber performance on oil-fired units. It has also been reported that corrosion problems and difficulties in obtaining a satisfactory precipitate of the magnesium and calcium salts were experienced.

2.3.4 Mechanical Collection

As with wet scrubbers, multicyclone systems are not normally designed strictly for particulate control on oil-fired units. Theoretically, they could be utilized to control acid smut or soot emissions during transient upset conditions. No test data were found for this type of control.

2.4 CONTROLS FOR GAS-FIRED BOILERS

Due to the nature of emissions from industrial gas-fired units (as delineated previously in subsection 2.1), controls for particulate matter are not employed. Theoretically, one could apply any of the four control techniques except wet scrubbing, which would require an excessive pressure loss, to capture the fine particle emissions. Mechanical collectors would be unable to collect these fine emissions but could potentially eliminate any excessive particulate emissions during transient operations. At this point, no need is seen for particulate control systems with properly operated and maintained gas-fired units.

TABLE 27. BOSTON EDISON SCRUBBER TESTS MYSTIC STATION - OIL-FIRED BOILER NO. 6[77]

Performance factor	Test number			
	1	2	3	4
Sulfur content of fuel (wt %)	2.15	2.10	1.89	2.04
Ash content of fuel (wt %)	0.09	0.10	0.07	0.07
Boiler operating capacity (MW)	146.0	144.0	151.0	148.0
Inlet particulate loading ($lb/10^6$ Btu)*	0.277	0.171	0.281	0.108
Outlet particulate loading ($lb/10^6$ Btu)*	0.085	0.085	0.106	0.059
Particulate removal efficiency (wt %)	69.5	50.5	62.4	45.7
Sulfur dioxide removal efficiency (wt %)	92.7	91.4	93.4	89.2

*To convert from $lb/10^6$ Btu to ng/J, multiply by 430.

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3.0 CANDIDATES FOR BEST SYSTEMS OF EMISSION REDUCTION

3.1 CRITERIA FOR SELECTION

In Section 2.0 — Emission Control Techniques — control methods were discussed that would most likely be used to collect particulate matter from industrial boilers. This section provides analyses of those control techniques which are capable of meeting three key emission levels (i.e., stringent, intermediate, and moderate). This analysis is based primarily on the technical or engineering capabilities of the various control devices and on the economic, energy, and environmental impacts incurred at these three emission control levels.

In the ensuing discussions of emission control technologies candidate technologies are compared using these three emission control levels. These control levels were chosen only to encompass all candidate technologies and form bases for comparison of technologies for control of specific pollutants considering performance, costs, energy, and nonair environmental effects.

From these comparisons, candidate "best" technologies for control of individual pollutants are recommended for consideration in any subsequent industrial boiler studies. These "best technology" recommendations do not consider combinations of technologies to remove more than one pollutant and have not undergone the detailed environmental, cost, and energy impact assessments necessary for regulatory action. Therefore, the levels of "moderate, intermediate, and stringent" and the recommendation of "best technology" for individual pollutants are not to be construed as indicative of the regulations that might be developed for industrial boilers. EPA will perform rigorous examination of several comprehensive regulatory options before any decisions are made regarding standards for emissions from industrial boilers.

The controlling factor in assessing overall applicability will be the demonstrated performance capabilities of a specified control system as described in Section 2.0. Data which were purely theoretical, fragmented, or of questioned origin and which were not utilized in Section 2.0, will not be used in Section 3.0 to determine candidate systems.

The applicability of a particular control method with respect to the seven boiler firing methods will be reviewed as well as its status of development.

Economic impacts will be based mainly on the capital and operating costs for the various control methods. The energy impact will be treated as a function of the energy consumed by the operation of the control system per se while environmental impacts will be defined by such factors as stack emissions, sludge disposal, dry fly ash disposal, and/or water pollution.

3.1.1 Moderate Level of Control

The "moderate" level, which has been defined as 107.5 ng/J (0.25 $lb/10^6$ Btu), is the least stringent control level to be reviewed. This level will require some degree of removal for the coal-fired boilers (roughly 50 to 97 percent efficiency), minimal removal for residual oil-fired boilers (< 31 percent efficiency) and no removal for the distillate oil and natural gas-fired boilers.

3.1.2 Stringent Level of Control

The stringent level of control, which has been set at 12.9 ng/J (0.03 lb/10^6 Btu) is representative of the level specified by EPA for utility boilers in the Federal Register of June 11, 1979. This (12.9 ng/J) level will require substantial emission reductions for coal-fired boilers (94 to 99.65 percent efficiency) and up to 92 percent efficiency for residual oil-fired units. There are indications that control at the stringent level may be very difficult on a continued, long-term basis (even for utility boilers).

3.1.3 Intermediate Level of Control

This level has been selected at 43 ng/J (0.1 lb/10^6 Btu) (the original NSPS for utility boilers), and represents a typical emission limitation enforced in many states. This level appears to be the critical value below which significant cost and energy penalties may occur. Because this level has been in effect for several years, cost data are available for control at this level and will be utilized in Section 4.0.

For coal-fired boilers controlled at the intermediate level, efficiencies of 80 to 98.82 percent would be required while residual oil-fired boilers would require efficiencies ranging up to 72 percent.

The three levels of emission control selected should provide a realistic range within which to work and properly assess the impacts of particulate reductions from the boilers selected for evaluation.

3.2 BEST CONTROL SYSTEMS FOR COAL-FIRED BOILERS

3.2.1 Moderate Reduction Controls

A summary description of four coal-fired boilers, their control devices, and the impact of moderate control upon such factors as cost, energy consumption, reliability, etc., is presented in Table 28. The various factors

TABLE 28. APPLICABILITY OF PARTICULATE EMISSION CONTROL TECHNIQUES TO ACHIEVE A MODERATE EMISSION LEVEL OF 107.5 ng/J (0.25 lb/10^6 Btu) FOR COAL-FIRED INDUSTRIAL BOILERS

Boiler type and heat input MW (10^6 Btu/hr)	Control device	Technical capability to meet moderate level	Cost impact	Energy impact	Environmental impact	Boiler operation or safety	Reliability	Availability to sources after 1/81	Adaptability to existing sources	Multipollutant control capability	Overall ranking*
Pulverized	MC	C	A	B	C	A	A	A	C	D	C
58.6 & 117.2	WS	B	C	D	C	A	B	A	C	A	C
(200) (400)	ESP	A	C	A	A	A	A	A	C	C	A
	FF	A	C	C	A	B	A	A	C	B	B
Spreader stoker	MC	B	A	B	B	A	A	A	C	D	A
44	WS	B	B	C	C	A	B	A	C	A	B
(150)	ESP	A	C	A	A	A	A	A	C	C	B
	FF	A	C	C	A	B	A	A	C	B	B
Chain grate stoker	MC	A	A	B	A	A	A	A	C	D	A
22	WS	A	B	B	B	A	B	A	C	A	B
(75)	ESP	A	D	A	A	A	A	A	C	C	C
	FF	A	D	C	A	B	A	A	C	B	C
Underfeed stoker	MC	B	A	B	B	A	A	A	C	D	B
8.8	WS	B	C	D	C	A	B	A	C	A	C
(30)	ESP	A	D	A	A	A	A	A	C	C	B
	FF	A	D	C	A	B	A	A	C	B	C

*Rating System - Each control device is rated by a letter code (A = best; B = good; C = acceptable; D = poor; E = inappropriate) relating to each factor listed in the table. The overall ranking applies to all factors listed as well as those discussed in the text.

Note: MC - Multitube Cyclone
WS - Wet Scrubber
ESP - Electrostatic Precipitator
FF - Fabric Filter

listed in the table, which would be affected by the installation of a given control device on each of the boilers, are discussed in the following paragraphs.

The third column assess the technical capability of the control option to meet the moderate emission level of 107.5 ng/J (0.25 lb/10^5 Btu). This capability is a function of the boilers' uncontrolled emission rate (refer to Table 12), the mass median diameter of these uncontrolled emissions (refer to Table 13), the established efficiency range for the control device, and, in the case of electrostatic precipitators, the variations in sulfur and sodium (or alkali) content of the coal.

Economic factors considered, Column 4, are the installed capital costs and the annual operating costs reported for each of the control devices. Generally, installed capital costs are lowest for multitube cyclones and increase for scrubbers, precipitators, and fabric filters, in the order named.

Operating costs are lowest for precipitators and mechanical collectors, followed by fabric filters and scrubbers, although these costs are strongly dependent on site-specific factors, particularly sulfur and alkali metal content of the coal burned. Electrostatic precipitators and fabric filters are ranked unfavorably in terms of cost because of variations in coal properties and uncertainties in bag service life, respectively.

The energy impact of each control system (Column 5) is based on the required pressure drop through the device to attain the necessary fly ash collection for the particular boilers in question. Precipitators, operating at less than 0.25 kPa (1 inch W.C.) resistance, are shown to be the least energy-intensive of the four control methods.

The environemntal impact of each device, Column 6, is examined under four categories; fly ash emissions from the stack, dry fly ash disposal, sludge disposal, and water pollution. The wet scrubber is rated the lowest because of sludge disposal and potential water pollution problems.

With respect to boiler operation and safety, Column 7, the fabric filter (which does not have "natural bypass" capabilities like an ESP or MC) appears to be the only device that has potential for problems in that inadequate fabric cleaning procedures could result in sudden pressure drop increases that might affect the operation of the boiler. However, proper attention to the fabric filter operating parameters should minimize problems in this area.

Reliability of the various control devices (Column 8) appears to be generally adequate with the scrubber rated slightly lower than the other control methods because of corrosion problems and ancillary equipment requirements and, therefore, the potential for more equipment failure.

The availability of all four methods of control to sources installed and operated after January 1981, is projected to be no problem because of the fact that all are well-established technologies.

Adaptability to existing sources, Column 9, is rated as only acceptable for all control approaches since site-specific problems will be the controlling factors for most retrofit installations.

The wet scrubber, Column 10, has been shown to be the best system for multipollutant control due to its added capability for absorption of SO_2 and other gaseous pollutants. The baghouse is rated good in terms of multipollutant control, due to active research work underway in the area of dry SO_2 removal.[1] The emergence of dry scrubbing technology as a nonregenerable form of flue gas desulfurization has culminated in the first U.S. commercial installation at Strathmore Paper Co. in Strathmore, Massachusetts. This system, designed and installed by MikroPul Corp., consists of a spray dryer followed by a baghouse. It is installed on a pulverized coal boiler burning 2.5 percent sulfur coal and guaranteed for 75 percent SO_2 removal. A second industrial facility, the Celanese Corp. in Cumberland, Maryland, has adopted this technology with completion of its spray dryer/filter system scheduled for early 1980. This system, developed jointly by Rockwell International and Wheelabrator-Frye, will consist of a lime-based spray dryer followed by a baghouse. It will control emissions from a stoker-fired boiler burning 1.5 to 2.0 percent sulfur coal at a rated flue gas flow of 1841 m^3/min (65,000 acfm). Utility groups planning on installing dry scrubbing systems are the Basin Electric Power Cooperative (Bismarck, N. Dak.) and the Otter Tail Power Co. (Beulah, N. Dak.). The Basin Electric Power Cooperative plans facilities at its Laramie River Station - Unit 3 in Wheatland, Wyoming and its Antelope Valley Plant in Beulah, N. Dak. The Laramie River boiler which is rated at 500 Mw_e and a flue gas rate of 56,634 m^3/min (~ 2×10^6 acfm), will burn subbituminous coal from Wyoming with a maximum sulfur content of 0.81 percent. The collection system will consist of a lime-based, horizontal spray dryer followed by an electrostatic precipitator. Startup is anticipated for 1980. The Antelope Valley boiler is rated at 440 Mw_e, a flue gas volume of 50,000 m^3/min (1.8×10^6 acfm), and will burn 1.22 percent sulfur lignite. This system, slated for operation in 1982, includes a lime-based spray dryer followed by a baghouse. The Otter Tail Power Co. Coyote Station boiler is rated at 410 Mw_e, a flow rate of 53,519 m^3/min (1.89×10^6 acfm), and will burn 0.78 percent sulfur lignite. This system will employ a sodium carbonate - (soda ash or Na_2CO_3) based spray dryer followed by a baghouse and is scheduled for completion in late 1981.

Dry scrubbing is accomplished by dry injection of naturally occurring sorbents such as soda ash, trona (a hydrous sodium carbonate), and nahcolite (sodium bicarbonate), or by spray drying, in which heat from the flue gas is used to evaporate the water from a sprayed alkali slurry such as lime or soda ash. The outcome in either situation is the formation of a dry-powder mixture of fly ash and sulfates, which is collected by a baghouse or electrostatic precipitator. The advantages of dry scrubbing over wet scrubbing are: improved waste handling, less corrosion potential, lower investment and operating costs, and less energy and water consumption. One important limitation of dry scrubbing technology is that it appears to be economically feasible only at low SO_2 concentrations in the flue gas.

For more information on SO_2 removal options, the reader is referred to the technology assessment report on flue gas desulfurization.

Other factors affecting the applicability of particulate control that are not listed in Table 28 are: status of development of the control option, operation and maintenance requirements, and compatibility with and impact on other pollutant control systems.

Operation and maintenance requirements which are important for all of the control devices from the standpoint of system performance are equally or more important for stringent and intermediate control requirements.

The aspect of compatibility with other control systems requires a careful and thorough review and any interactions among the various control techniques must be evaluated. Available data from a series of tests performed by KVB Engineering, Inc. in 1976 sheds some light on the effects of combustion modifications to reduce NO_x emissions on particulate emissions.[2] Some of the more important conclusions resulting from this study are outlined as follows:

1. Reduced excess air - Particulate emissions decreased by as much as 30 percent in four of six tests. However, the fraction of fine particles increased in the case of a chain grate boiler.
2. Staged combustion air - Particulate emissions increased by 20 to 48 percent in three of six tests.
3. Burners out of service - Particulate emissions increased by 25 to 95 percent.
4. Burner register adjustment - No significant effect on particulate emissions.
5. Flue gas recirculation - Recirculating 25 percent of the flue gas resulted in a nitrogen oxides reduction of about 12 percent and a particulate emission increase of about 15 percent.
6. Reduced firing rate - In one test, nitrogen oxides increased by 10 percent and particulates decreased by 45 percent.

Although these data are based on a limited number of tests, they do indicate some potential problems when NO_x reduction techniques are to be employed in conjunction with particulate control; however, the reader is referred to the ITAR on Combustion Modification for NO_x control for a more detailed discussion. Since the preceding discussion also applies to stringent and intermediate control levels, it will not be repeated in the latter sections.

3.3.2 Stringent Reduction Controls

A summary of the four coal-fired boilers, their control devices, and the influence of stringent control standards upon such factors as cost, energy consumption, reliability, etc., is presented in Table 29. This level of emission reduction would have the greatest adverse impact on the cost of control as well as precluding (in some cases) the sole use of multitube cyclones, wet scrubbers and even precipitators for the very low sulfur coals.

The rationale for assigning the ratings given to each control option is the same as that described previously for moderate emission levels and for all dust collector categories.

The stringent level of control would certainly preclude the sole use of multitube cyclones and in all cases except for chain grate boilers (because of particle size and inlet loading) the wet scrubber would be excluded from consideration. Precipitators and fabric filters would be required in most cases and at low sulfur coal burning installations (or small boilers < 50 MW or 171 × 10^6 Btu/hr heat input) fabric filters would appear to be the more logical choice.

3.2.3 Intermediate Reduction Controls

A summary of the four coal-fired boilers, their control devices, and the impact of intermediate control upon economics, energy consumption, reliability, etc., is presented in Table 30. It is seen that at this level of emission control, more options would be open to the industrial boiler operator as each of the control devices could be used on one or more of the boilers under study.

3.3 BEST CONTROL SYSTEMS FOR OIL-FIRED BOILERS

The three levels of control which have been outlined previously also apply to the oil-fired boilers. Because of the less stringent efficiencies (see Table 31) that would be required to collect uncontrolled emissions from the residual and distillate oil-fired units, the small particle size of the

TABLE 29. APPLICABILITY OF PARTICULATE EMISSION CONTROL TECHNIQUES TO ACHIEVE A STRINGENT LEVEL OF 12.9 ng/J (0.03 lb/10^6 Btu) FOR COAL-FIRED INDUSTRIAL BOILERS

Boiler type and capacity GJ/hr (10^6 Btu/hr)	Control device	Technical capability to meet stringent level	Cost impact	Energy impact	Environmental impact	Boiler operation or safety	Reliability	Availability to sources after 1/81	Adaptability to existing sources	Multi-pollutant control capability	Overall ranking*
Pulverized	MC	E	E	D	D	A	D	A	C	D	E
211	WS	D	D	D	D	A	D	A	C	B	D
(200)	ESP	B	C	A	A	A	B	A	C	C	B
	FF	A	C	B	A	B	A	A	C	B	A
Spreader stoker	MC	E	E	D	D	A	D	A	C	D	E
158.2	WS	C	D	C	D	A	C	A	C	B	C
(150)	ESP	B	C	A	A	A	B	A	C	C	B
	FF	A	C	B	A	B	A	A	C	B	A
Chain grate	MC	E	E	D	D	A	D	A	C	D	E
stoker	WS	B	C	C	D	A	C	A	C	B	B
79.1	ESP	B	C	A	A	A	B	A	C	C	B
(75)	FF	A	C	B	A	B	A	A	C	B	A
Underfeed	MC	E	E	D	D	A	D	A	C	D	E
stoker	WS	C	D	D	D	A	C	A	C	B	C
31.6	ESP	B	C	A	A	A	B	A	C	C	B
(30)	FF	A	C	B	A	B	A	A	C	B	A

*Rating System - Each control device is rated by a letter code (A = best; B = good; C = acceptable; D = poor; E = inappropriate) relating to each factor listed in the table. The overall ranking applies to all factors listed as well as those discussed in the text.

Note: MC - Multitube Cyclone
WS - Wet Scrubber
ESP - Electrostatic Precipitator
FF - Fabric Filter

TABLE 30. APPLICABILITY OF PARTICULATE EMISSION CONTROL TECHNIQUES TO ACHIEVE AN INTERMEDIATE LEVEL OF 43 ng/J (0.10 lb/10^6 Btu) FOR COAL-FIRED INDUSTRIAL BOILERS

Boiler type and Capacity GJ/hr (10^6 Btu/hr)	Control device	Technical capability to meet intermediate level	Cost impact	Energy impact	Environ-mental impact	Boiler operation or safety	Reliability	Avail-ability to sources after 1/81	Adapt-ability to existing sources	Multi-pollutant control capability	Overall ranking*
Pulverized	MC	E	E	B	D	A	D	A	C	D	E
211	WS	C	D	D	D	A	C	A	C	A	D
(200)	ESP	A	C	A	A	A	B	A	C	C	A
	FF	A	C	C	A	B	A	A	C	B	B
Spreader stoker	MC	D	E	B	D	A	D	A	C	D	D
158.2	WS	B	D	C	C	A	C	A	C	A	B
(150)	ESP	A	C	A	A	A	B	A	C	C	A
	FF	A	C	C	A	B	A	A	C	B	B
Chain grate	MC	D	E	B	D	A	D	A	C	D	D
stoker	WS	B	C	C	C	A	C	A	C	A	B
79.1	ESP	A	D	A	A	A	B	A	C	C	A
(75)	FF	A	D	C	A	B	A	A	C	B	B
Underfeed	MC	C	A	B	C	A	B	A	C	D	C
stoker	WS	C	C	C	C	A	C	A	C	A	C
31.6	ESP	A	D	A	A	A	B	A	C	C	A
(30)	FF	A	D	C	A	B	A	A	C	B	B

*Rating System - Each control device is rated by a letter code (A = best; B = good; C = acceptable; D = poor; E = inappropriate) relating to each factor listed in the table. The overall ranking applies to all factors listed as well as those discussed in the text.

Note: MC - Multitube Cyclone
WS - Wet Scrubber
ESP - Electrostatic Precipitator
FF - Fabric Filter

emitted fly ash, and the hygroscopic nature of the oil fly ash, an electrostatic precipitator would be the preferred device at any of the control levels. Fabric filters are a second choice until more experience is available for the filtration of hygroscopic aerosols.

3.4 BEST CONTROL SYSTEMS FOR GAS-FIRED BOILERS

Because of the fact that uncontrolled emissions from gas-fired units are considerably less than the stringent level of control that has been selected, no need is seen for control of properly operated gas-fired boilers.

3.5 SUMMARY

A summary of the data presented in this section is given in Table 31. This table lists each boiler type, the type of fuel fired, the range of uncontrolled emissions excerpted from Table 12 and the average mass median diameter (MMD) for these uncontrolled emissions (Table 13). Following this information, the three levels of control are indicated along with the range of efficiencies that would be required to achieve the stated emission levels.

The next three columns indicate the minimum acceptable control device that would be required to meet each of the control limits based upon the technological capabilities presented in Section 2.0. The control equipment has been "ranked" at the bottom of Table 31 in terms of overall capabilities. It might be argued that electrostatic precipitators should be rated ahead of fabric filters because of greater usage and hence experience, but the higher efficiency and lesser dependence upon fuel sulfur content are the reasons for giving a slight advantage to the fabric filter.

The definition of "minimum acceptable control device" should be interpreted as follows: if, for example, a wet scrubber (WS) is listed in the table as the device capable of meeting the emission limitation, then an

TABLE 31. PARTICULATE CONTROL OPTIONS AND REQUIRED EFFICIENCIES

Boiler type	Uncontrolled emissions range ng/J (lb/10^6 Btu) See Table 12	Particle size average MMD (μm) See Table 13	Level of emission control and efficiency (%) required to achieve that level ng/J (lb/10^6 Btu)			Minimum acceptable control device required at specified level*		
			Stringent 12.9 (0.03)	Intermediate 43 (0.10)	Moderate 107.5 (0.25)	Stringent	Intermed.	Mod.
A. Pulv. Coal 3.5% S 10.6% A	3087-3280 (7.18-7.63)	16.7	99.58-99.61	98.61-98.69	96.52-96.71	FF	ESP	ESP
2.3% S 13.2% A	3436-3651 (7.99-8.49)	16.7	99.62-99.65	98.75-98.82	96.87-97.06	FF	ESP	ESP
0.9% S 6.9% A	1720-1827 (4.00-4.25)	16.7	99.25-99.29	97.50-97.65	93.75-94.12	FF	ESP	ESP
0.6% S 5.4% A	1935-2055 (4.50-4.78)	16.7	99.33-99.37	97.78-97.91	94.44-94.77	FF	ESP	WS
B. Sp. Stoker 3.5% S 10.6% A	2511 (5.84)	59	99.49	98.29	95.72	FF	WS	WS
0.9% S 6.9% A	1397 (3.25)	59	99.08	96.92	92.31	FF	WS	WS
0.6% S 5.4% A	1574 (3.66)	59	99.18	97.27	93.17	FF	WS	WS
C. Chain Grate 3.5% S 10.6% A	967.5 (2.25)	88	98.67	95.56	88.89	WS	WS	MC
0.9% S 6.9% A	537.5 (1.25)	88	97.60	92.00	80.00	WS	WS	MC
0.6% S 5.4% A	606.3 (1.41)	88	97.87	92.91	82.27	WS	WS	MC
D. Underfeed Stoker 3.5% S 10.6% A	387-963.2 (0.90-2.24)	16	96.7-98.7	88.9-95.5	72.2-88.8	ESP	ESP	ESP
0.9% S 6.9% A	215-537.5 (0.50-1.25)	16	94-97.6	80.0-92.0	50.0-80.0	ESP	WS	MC
0.6% S 5.4% A	241-602 (0.56-1.40)	16	94.6-97.9	82.2-92.9	55.4-82.1	WS or FF	WS	MC
E. Residual Oil 3.0% S 0.1% A	16.6-154.6 (0.0385-0.3596)	<2	22.3-91.7	0-72.2	0-30.5	ESP only	ESP only	ESP only
F. Distillate Oil 0.5% S	3.74-14.6 (0.0087-0.0339)	<2	0-11.6	--	--	--	--	-
G. Natural Gas	0.34-6.45 (0.0008-0.015)	<2	--	--	--	--	--	-

*Control devices are ranked by their overall capabilities in terms of fuel sulfur content, overall efficiency considering particle size, capital cost, and energy required to operate:

1. Fabric Filter (FF)
2. Electrostatic Precipitator (ESP)
3. Wet Scrubber (WS)
4. Multitube Cyclone (MC)

electrostatic precipitator or a fabric filter would serve as well if not better. If only one or two devices can be used, they are so specified in Table 31.

3.6 REFERENCES

1. Miller, Irene. Dry Scrubbing Looms Large in SO_2 Cleanup Plans. Chemical Engineering. August 27, 1979. pp. 52-54.

2. Cato, G. A., L. J. Muzio, and D. E. Shore. Field Testing: Application of Combustion Modifications to Control Pollutant Emissions From Industrial Boilers - Phase II. EPA-600/2-76-086a. April 1976, pp. 192-209.

4.0 COST ANALYSIS OF CANDIDATES FOR BEST SYSTEMS OF EMISSION REDUCTION

4.1 COSTS TO CONTROL COAL-FIRED BOILERS

The cost of any particulate control system is of paramount importance to the potential user. Control equipment costs include the initial cost of many components such as those for the basic collector, connecting ductwork, storage hoppers, and ash handling system; installation costs; and the annual operating costs consisting of electricity, labor, maintenance, component replacement, and waste disposal.

The technical literature contains a myriad of economic studies for boilers utilizing particulate collection equipment. Unfortunately, most data represent costs for large, utility-sized boilers and not for the smaller, industrial-sized plants that are being studied in this technology assessment report. In addition, the available studies often use different costing procedures, different outlet emission rates, boiler sizes, and different years for the cost analyses, such that data comparisons are difficult. Further complication arises from the fact that this industrial boiler study is, in part, considering eight different oil-, gas-, and coal-fired boilers, four levels of emission control, four types of control equipment, and varying coal compositions. Although certain control devices cannot be used with all boilers or at each control level, there are still many combinations of the above for which costs will differ. It has not been practicable nor possible to obtain information from vendors or the literature on all of the possible boiler/fuel/control level/control device combinations. Therefore, the available data require interpolation and/or extrapolation along with sound engineering judgment to define those situations that have not been described directly.

Before presenting a standardized format for costs and their bases, general cost statistics and related information from available references will be reviewed to show the expected cost range for the boilers being studied.

4.1.1 PEDCo Study

A recent report by PEDCo[1] evaluated particulate control system costs for new utility boilers at three levels of emission control; 43.0, 22.0, and 13.0 ng/J (0.1, 0.05, and 0.03 lb/10^6 Btu, respectively). Two coals were considered; 0.8 percent sulfur, 8.0 percent ash and 3.5 percent sulfur, 14.0 percent ash. The costs presented in the PEDCo study, which refer to August 1980 dollars (using an inflation rate of 7.5 percent per year), have been discounted back to June 1978 dollars using the following equation:

$$P = Fe^{-rt} \tag{1}$$

where P = present cost

F = future cost

r = annual inflation rate

t = number of years

For the time period in question (2.17 years) and the inflation rate of 7.5 percent, Equation (1) reduces to P = 0.85F. The PEDCo study evaluated fabric filters (FF) and electrostatic precipitators (ESP) at the 13 ng/J (0.03 lb/10^6 Btu) level and considered only electrostatic precipitators and Venturi scrubbers at the two higher emission levels, 22.0 and 43.0 ng/J. Plant sizes analyzed ranged from 25 to 1000 MW electrical output. The relationships between boiler size and capital costs (including installation) are shown in Figures 23, 24, and 25 for varying levels of control, type of fuel

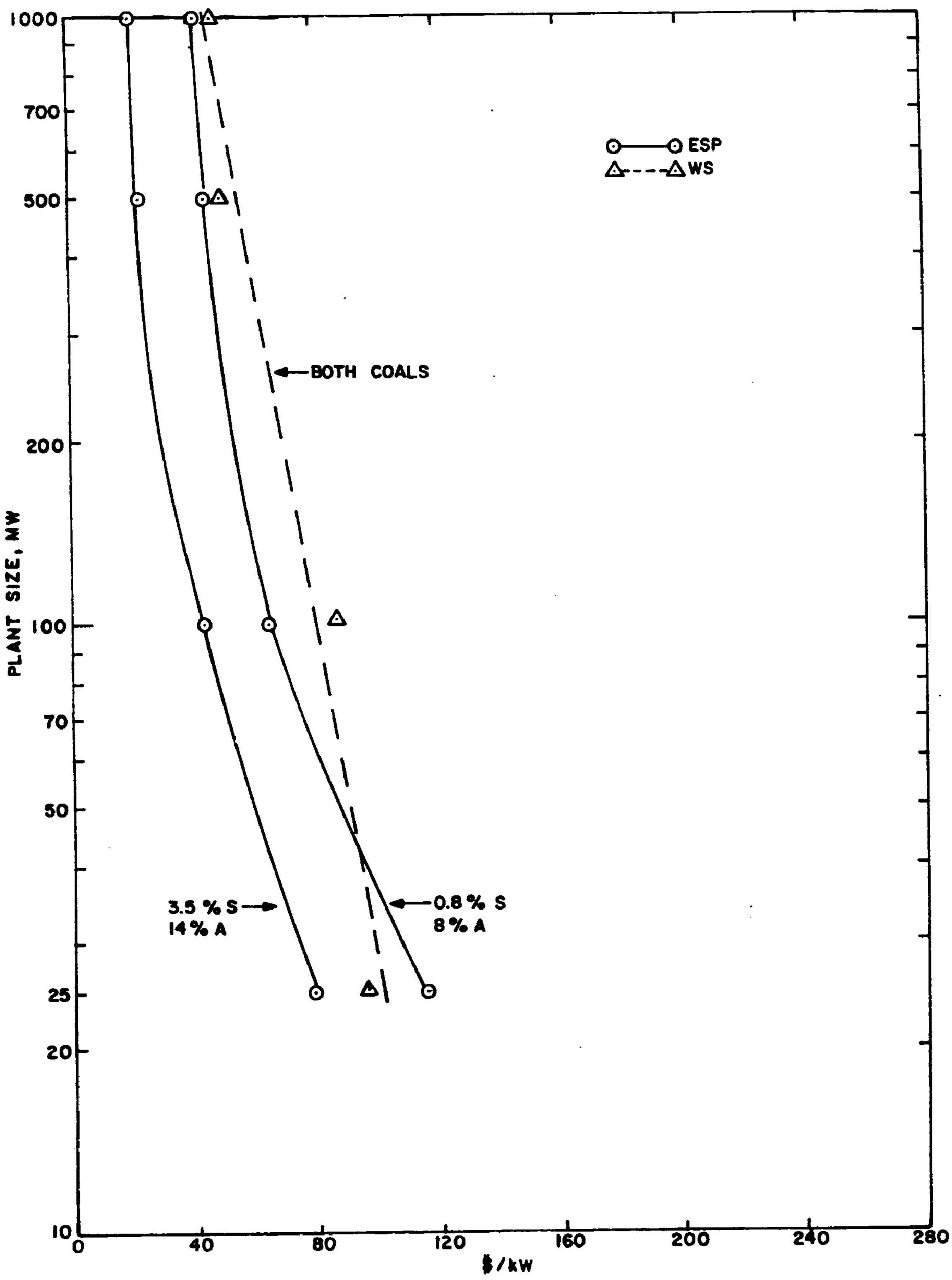

Figure 23. Capital costs of electrostatic precipitators and wet scrubbers on new coal-fired utility power plants. Emission level = 43 ng/J (0.1 lb/10^6 Btu). Raw data: Reference 1 - PEDCo Study.

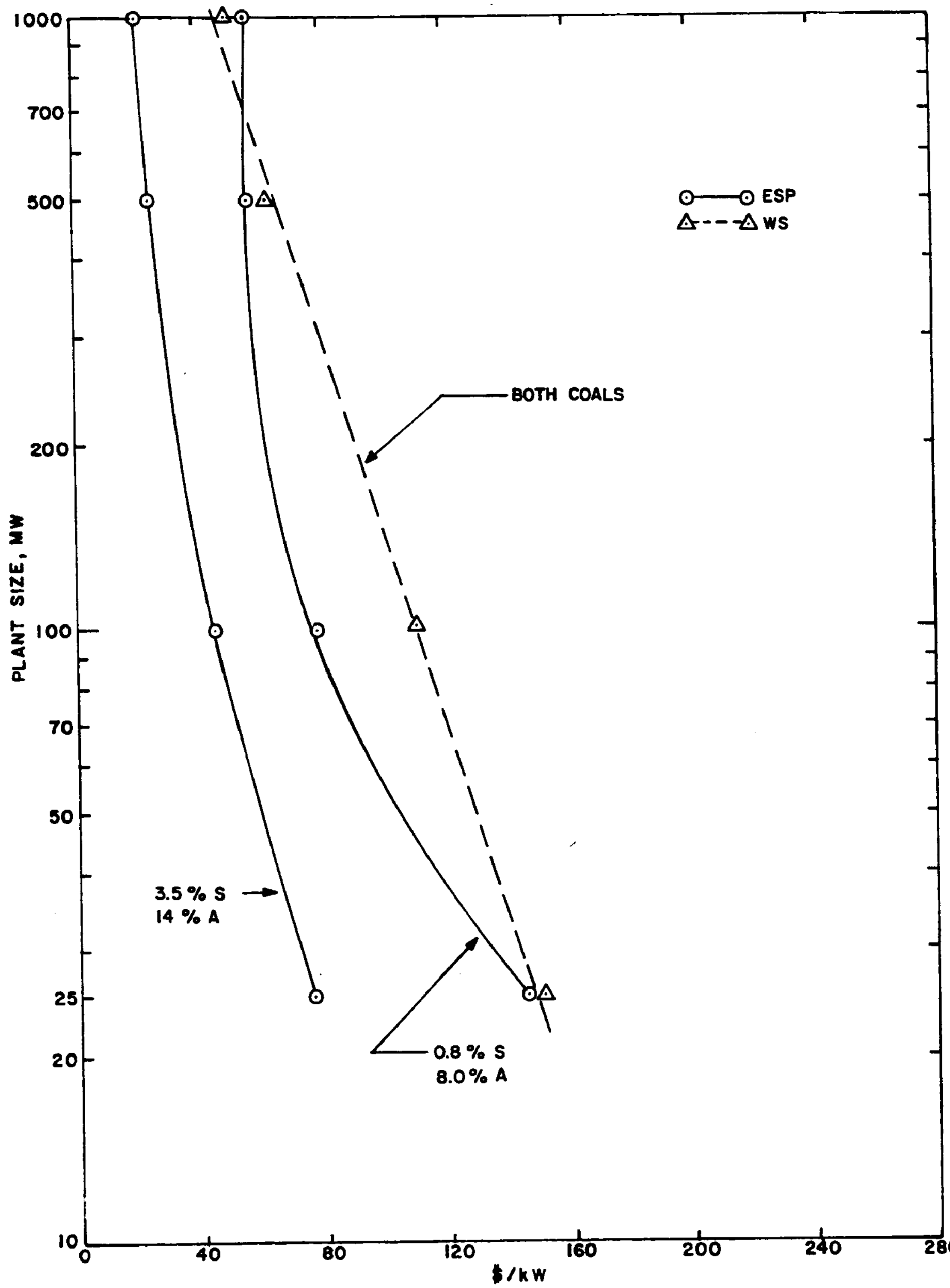

Figure 24. Capital costs of electrostatic precipitators and wet scrubbers on new coal-fired utility power plants. Emission level = 22 ng/J (0.05 lb/10^6 Btu). Raw data source: Reference 1 - PEDCo Study.

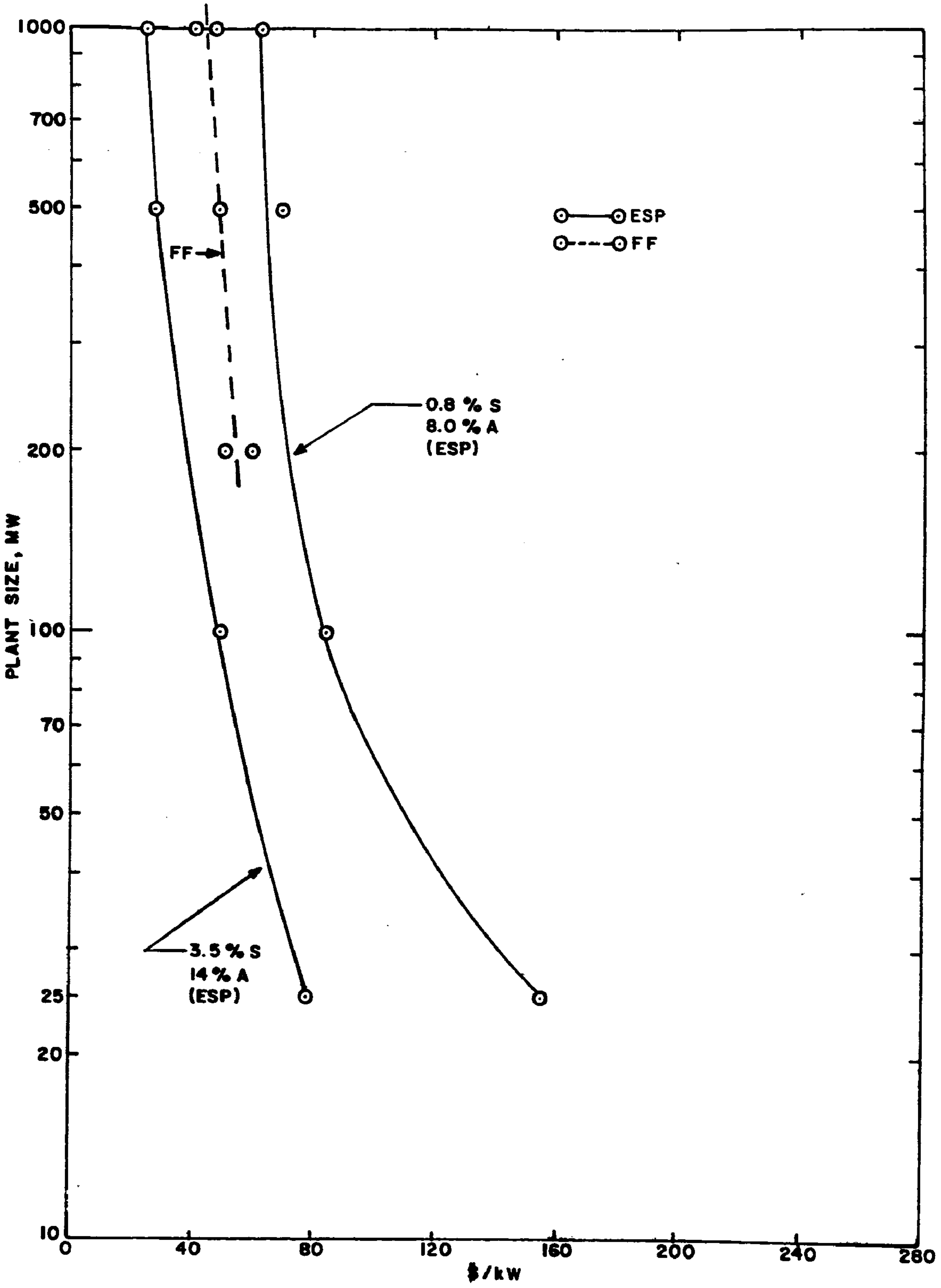

Figure 25. Capital costs of electrostatic precipitators and fabric filters on new coal-fired utility power plants. Emission level = 13 ng/J (0.03 lb/10^6 Btu. Raw data source: Reference 1 - PEDCo Study.

and method of control. These data show that (a) decreasing system size will increase the unit cost in terms of dollars per kW output, and (b) that there is an inverse relationship between sulfur content and ESP cost. (If it is desired to express the power costs in terms of steam production rate in kilograms per hour (kg/hr), the conversion factor for 1 dollar/kW will range from 185 to 278 mills/kg steam per hour for boiler/turbine efficiencies of 42.6 to 28.4 percent, respectively.)

4.1.2 Joy Manufacturing Study

Another cost study on large-sized boilers was performed by a leading manufacturer of control equipment for a boiler size of 500 to 600 MW_e while firing an unspecified low-sulfur coal.[2] Comparisons were made between a hot and cold ESP and a baghouse operating at 99.5 percent efficiency. If one assumes that the boiler is firing pulverized coal and that the uncontrolled emission rate is about 3,000 ng/J (7.0 $lb/10^6$ Btu), then the outlet emission rate is nearly equivalent to a reduction to the stringent level of emission. Items considered in the total investment cost were base equipment, accessories, plenums, flues, support structures, erection, insulation, ash handling, capacity charge (equal to $900/kW and based on the total expected power consumption required for the whole system) and land at $10,000 per acre. (The capacity charge is also referred to as a power penalty and is the cost that a utility assesses each bidder based on the projected full-load power consumption of the control device.) The resultant unit costs were $33.42/kW, $37.36/kW and $25.57/kW (output) for the hot ESP, cold ESP, and baghouse, respectively. The final conclusion of this study that baghouse investment costs are less than those for precipitators when firing low-sulfur coal is generally acknowledged.

Another study shows, Figure 26, the break-even point in operating costs between the two control approaches for specified efficiency levels and sulfur contents.[3]

4.1.3 GCA Study

Prior GCA studies under a previous contract with EPA* led to the compilation of cost statistics for fabric filters from several data sources, Table 32 and Figure 27. These data also suggest a decrease in unit cost (dollars/unit flow rate) as the system size increases, despite the fact that the solid line used for overall regression statistics (with a slope of nearly one) indicates a simple, direct relationship. However, the smaller slopes for the dashed lines representing the individual data classes used for the average values, suggest a reduction in unit cost with increasing size. Because these costs were prorated earlier to April 1978 by Chemical Engineering cost indexes, they are considered comparable to June 1978 reference data specified for this industrial boiler study.

4.1.4 IGCI Study

The IGCI study alluded to in Table 32 and Figure 27 presented costs for fabric filters, electrostatic precipitators and mechanical collectors for boiler sizes ranging from 3 to 73 MW (10 to 250 × 10^6 Btu/hr) input and for three different control levels.[11] Total Turnkey costs (adjusted to June 1978 prices) are graphed against boiler size for these data in Figure 28. It should be noted that the coal specified in the IGCI study is similar to the Eastern low-sulfur coal evaluated in this report:

0.8 percent S
7.5 percent ash
29,773 kJ/kg (12,800 Btu/lb)
5.0 percent water

*EPA Contract No. 68-02-2177

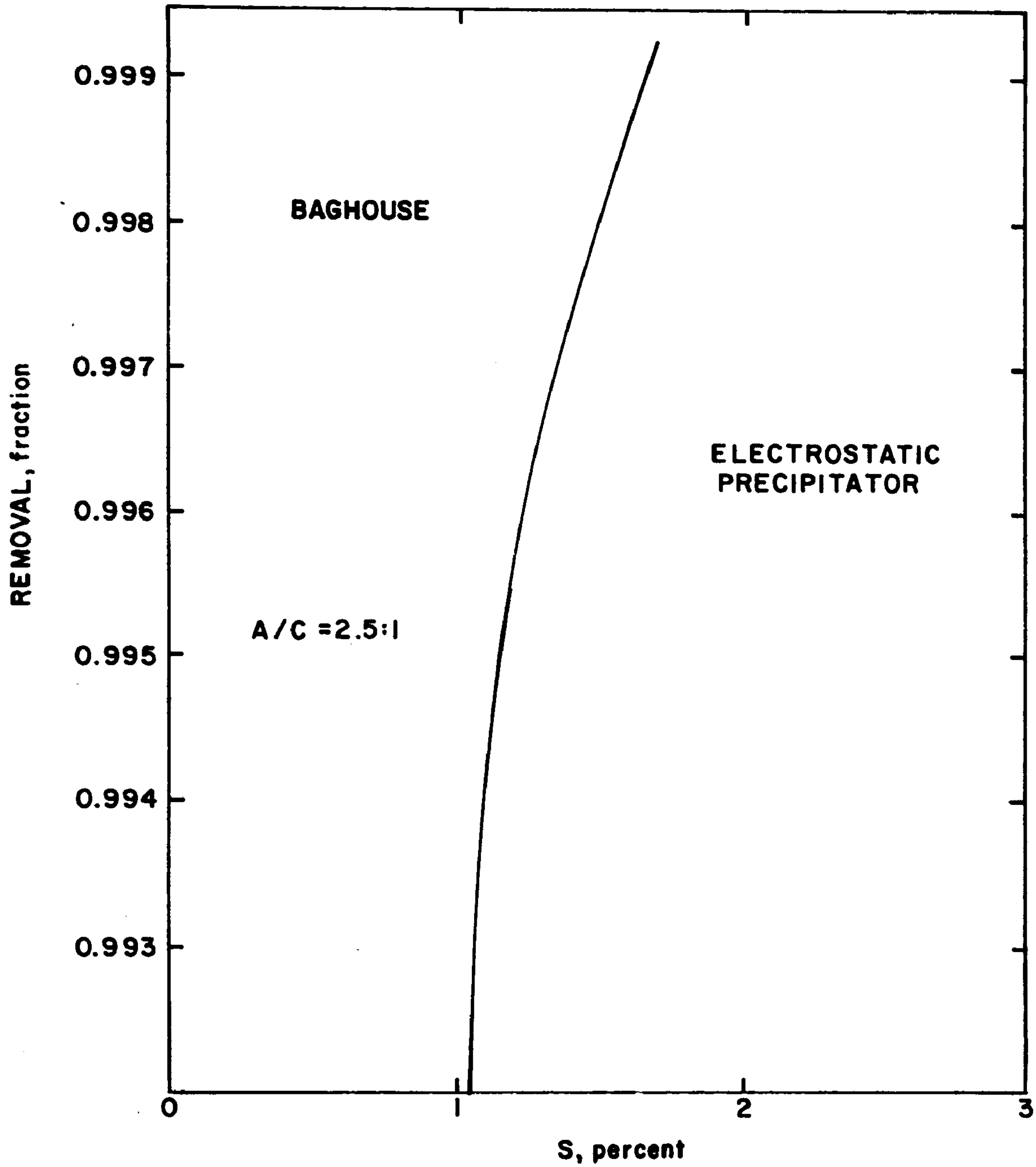

Figure 26. Approximate break-even point in operating costs between baghouses and precipitators for specified sulfur and efficiency levels.[3] (Argonne National Laboratory).

TABLE 32. SUMMARY CAPITAL AND OPERATING COSTS FOR UTILITY AND INDUSTRIAL BOILERS CONTROLLED BY FABRIC FILTERS

Data source \ Cost	Cost base year	Plant size (10^3 acfm)	Capital costs: Total dollars in millions, April 1978*	Capital costs: Dollars/acfm, Base year	Capital costs: Dollars/acfm, April 1978*	Annual operating cost† Dollars/acfm: Base year	Annual operating cost† Dollars/acfm: April 1978‡
I. Utility boilers							
EPRI[4]	1977	1,400	14.4	9.25	10.31	NA	NA
Joy Mfg. Co.[5]	4/77	2,500	15.5	5.50	6.20	0.31	0.33
Sunbury/GCA[6]	3/76	888	6.8	6.20	7.65	0.67	0.77
Nucla/GCA[7§]	8/75	260	4.2	12.75	16.15	1.11	1.34
				Avg = 10.0		Avg = 0.81	
II. Industrial boilers							
IGCI[8]	1/77	5.4	0.079	12.60	14.62	1.56	1.67
		46	0.34	6.44	7.47	0.81	0.87
		87	0.55	5.49	6.37	0.72	0.77
		116	0.74	5.48	6.36	0.70	0.76
EPA[9]	8/75	70	0.80	9.00	11.40	0.25	0.30
GCA case study[10]	1972	100	1.51	8.76	15.13	0.74	1.19
		200	2.62	7.57	13.08	0.68	1.10
		400	4.57	6.61	11.42	0.63	1.00
				Avg = 10.73		Avg = 0.96	

*Scaled from base year using Chemical Engineering Fabricated Equipment Cost Index.

†Includes electrical power, maintenance and repair, and bag replacement. Does not include amortized capital costs, space occupancy, depreciation, etc.

‡Scaled from base year using Chemical Engineering Fabricated Equipment Index for bag replacement cost (20 percent of operating cost), Construction Labor Index for labor (55 percent), and electric rate indexes for power cost (25 percent).

§Because Nucla is in a remote location with no shipping facilities and no skilled work force, their costs are atypically high. Therefore, the average unit costs based on all data sources are probably lower than indicated.

Note: NA = not available.

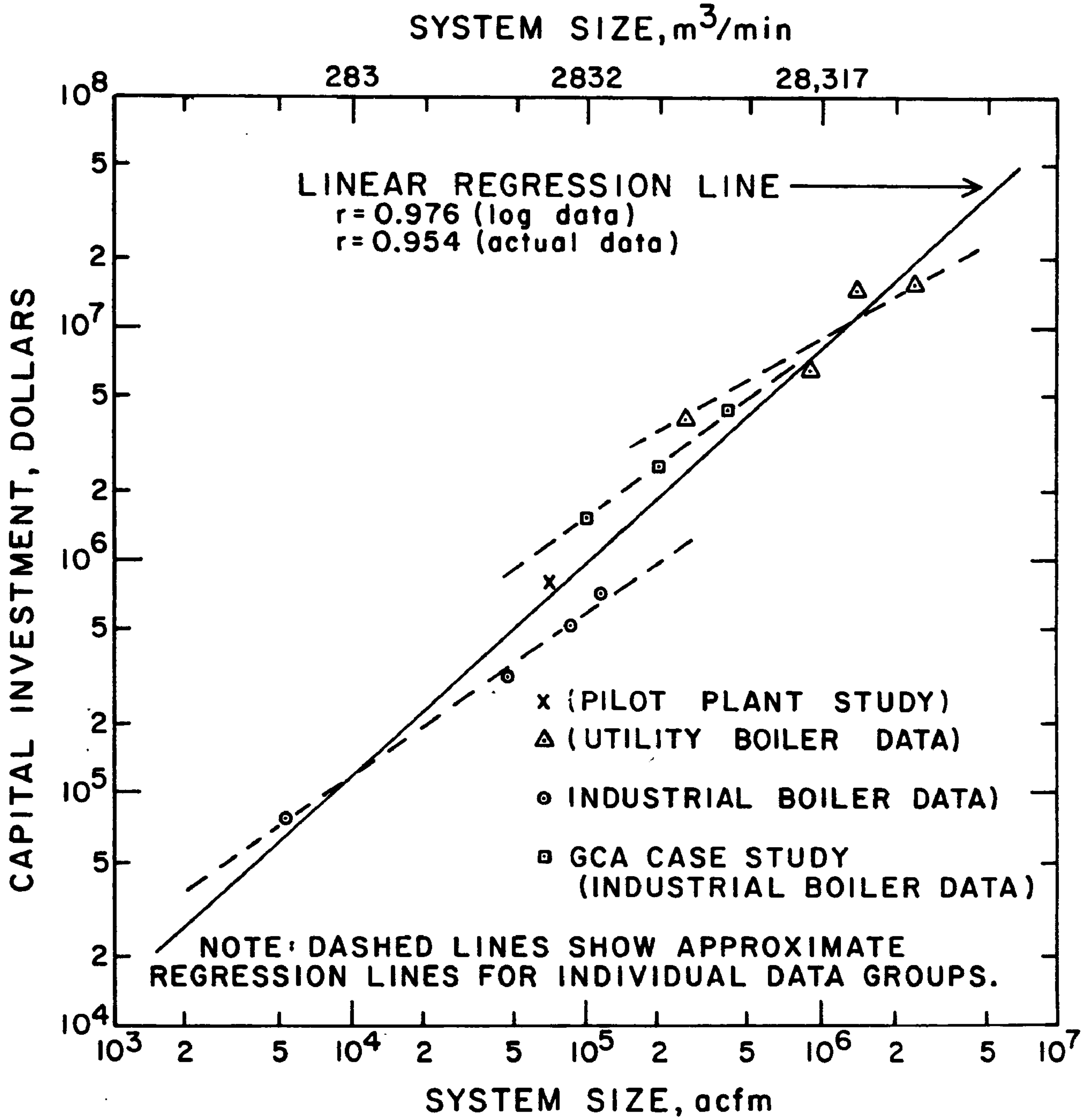

Figure 27. Capital Investment (April 1978 $) versus system size for several coal-fired boilers controlled by fabric filters (see Table 32).

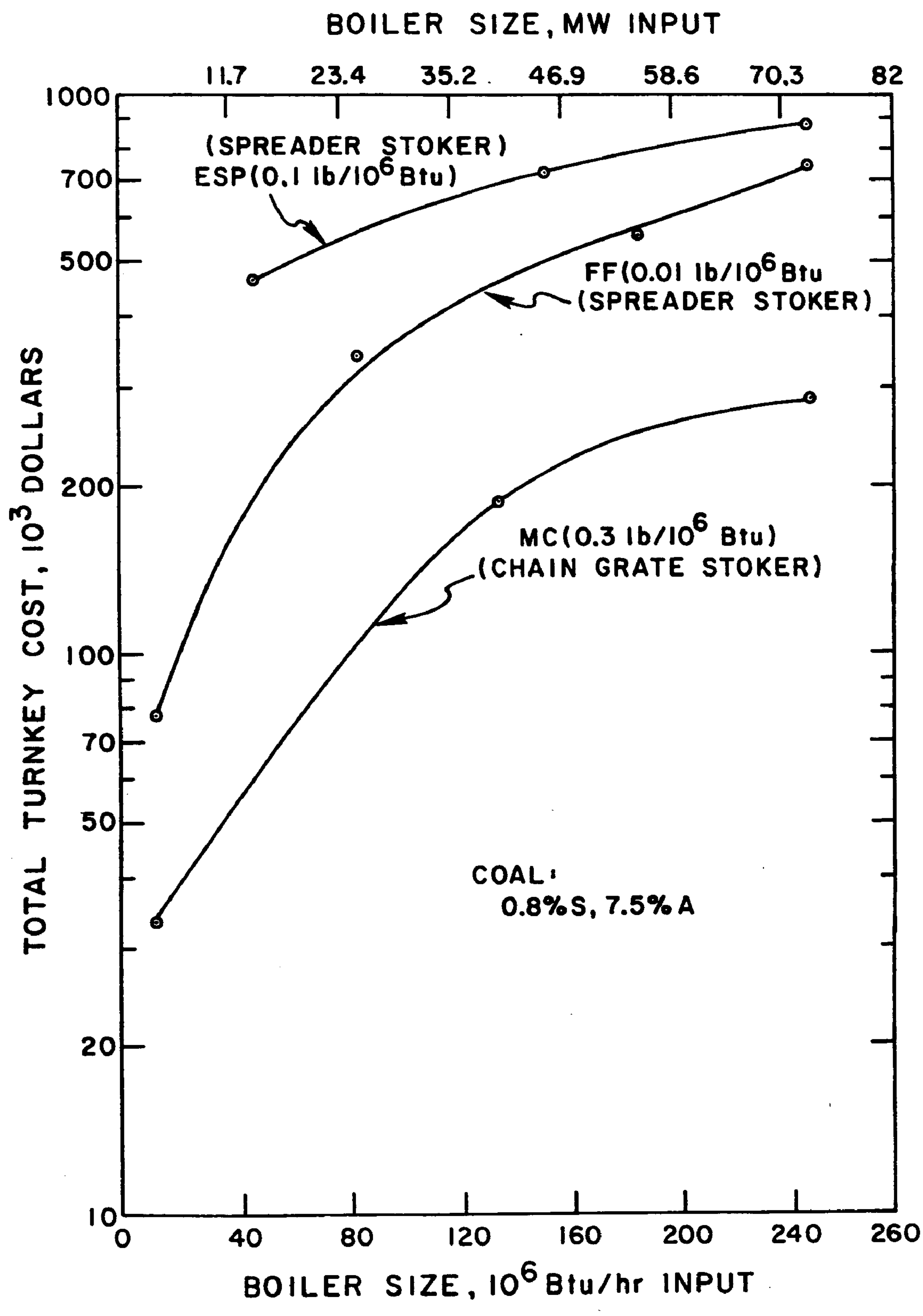

Figure 28. Total turnkey cost as a function of boiler size for three collectors at three emission levels. Raw data source: Reference 11 — IGCI Study.

Other assumptions in the IGCI cost analyses are:

- boilers operated at 65 percent load factor
- spreader stoker considered for fabric filter (FF) and ESP (65 percent of the particles > 40μ)
- chain grate stoker considered for mechanical collector (MC) (54 percent of the particles > 40μ)
- ash-handling system not included in costs
- all collectors have 5.1 cm (2 inches) of insulation
- outlet emission levels:
  - ESP - 43 ng/J (0.1 lb/10^6 Btu)
  - FF - 4.3 ng/J (0.01 lb/10^6 Btu)
  - MC - 129 ng/J (0.3 lb/10^6 Btu)

Because it is difficult to interpret collector costs when the outlet emission rate is different for each device, Figure 29 was prepared to define the cost in terms of weight of pollutant removed. This graph shows the fabric filter to be more cost effective than the ESP at boiler sizes roughly less than 50 MW (171 × 10^6 Btu/hr) input, for the emission rates specified above. (If the emission rate for the precipitator were lowered to correspond with that for the fabric filter, it is believed that the case for the fabric filter would be reinforced even further.) Other factors which should be considered are the additional amounts of fine particulate matter and trace elements that are removed by the baghouse at the 4.3 ng/J (0.01 lb/10^6 Btu) control level. The case for the baghouse becomes better and better when these factors as well as insensitivity to coal sulfur content are considered.

The IGCI costs are utillized in the detailed cost estimates later in this section. (See Tables 42 through 44.)

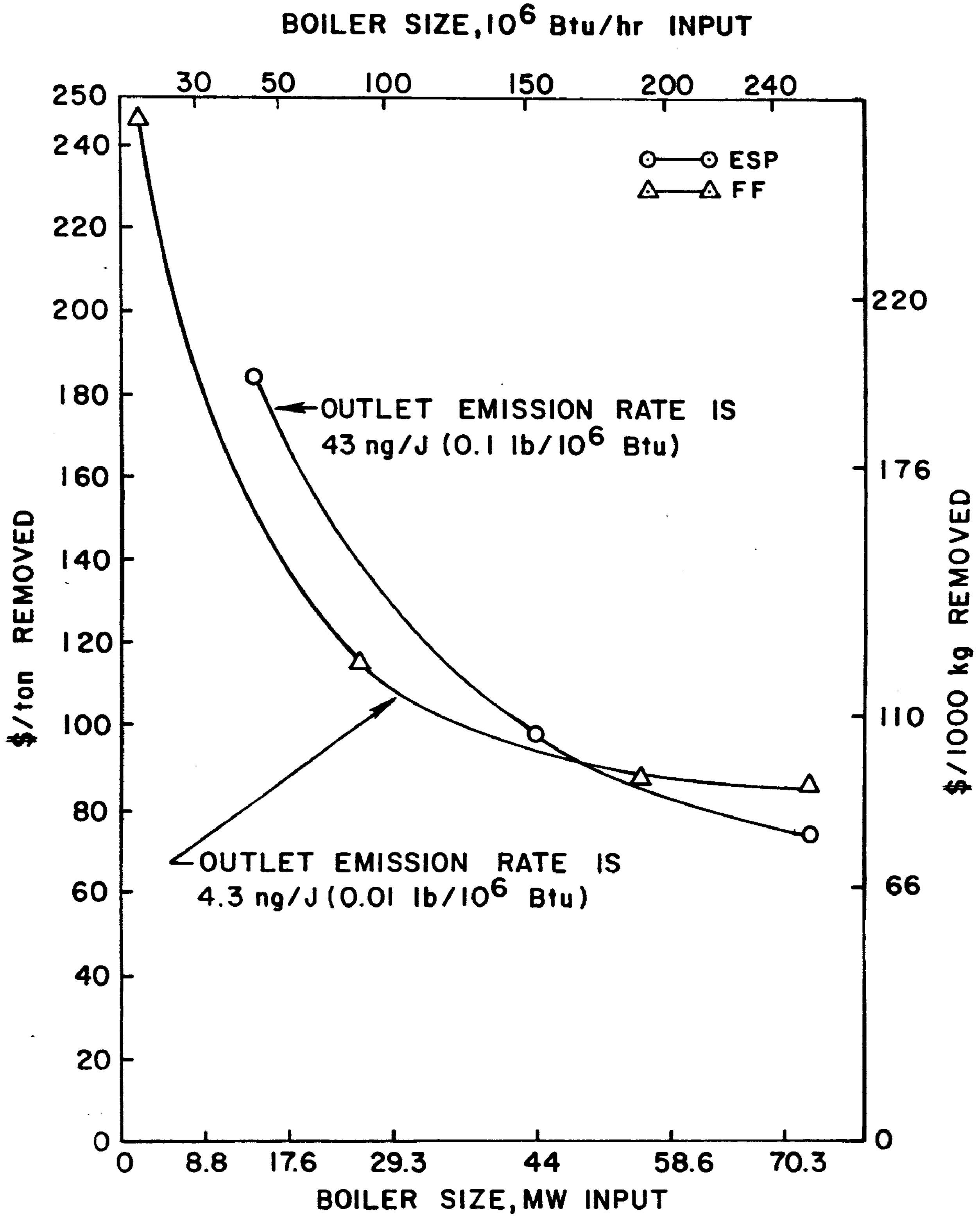

Figure 29. Cost-effectiveness of particulate removal as a function of boiler size for precipitators and baghouses installed on a spreader stoker boiler (based on annualized cost). Raw data source: Reference 11 — IGCI Study.

4.1.5 Manufacturer's Data

For electrostatic precipitators, vendor cost estimates were converted to unit costs (i.e., dollars per unit plate area) and graphed against the plate area to show the relative increase in control system cost as the system size decreases, Figure 30. For the sake of confidentiality, specific vendors are identified as A and B in the text and are listed irrespective of letter code in the reference section.[12] Generally, the ESP costs ranged between \$86 to \$516/m^2 (\$8 to \$48/ft^2) of plate area, depending on the size of the system required.

Additionally, cost data were provided by one of the vendors for the boiler sizes in question and for boilers 10 times as large. The statement from the manufacturer was basically that a tenfold increase in size led to a fivefold cost increase. This is shown in Figures 31 and 32 for installed basic equipment and installation alone, respectively, for a pulverized coal boiler. It may be inferred from these data that the cost impact upon the industrial boiler user for control equipment purchase and installation may be more severe than that for the utility boiler operator.

4.1.6 Detailed Cost Estimates

Detailed cost estimates are presented subsequently for 60 boiler/fuel/ control level/control device combinations. These cost estimates are given in June 1978 figures and are based on a number of assumptions regarding capitalization and annualization provided by PEDCo in their report entitled "The Population and Characteristics of Industrial/Commercial Boilers."

In addition to vendor-supplied cost data, efforts were made to model the capital and annualized costs of particulate control equipment installed on the standard boilers. Cost models developed by a leading equipment manufacturer[13]

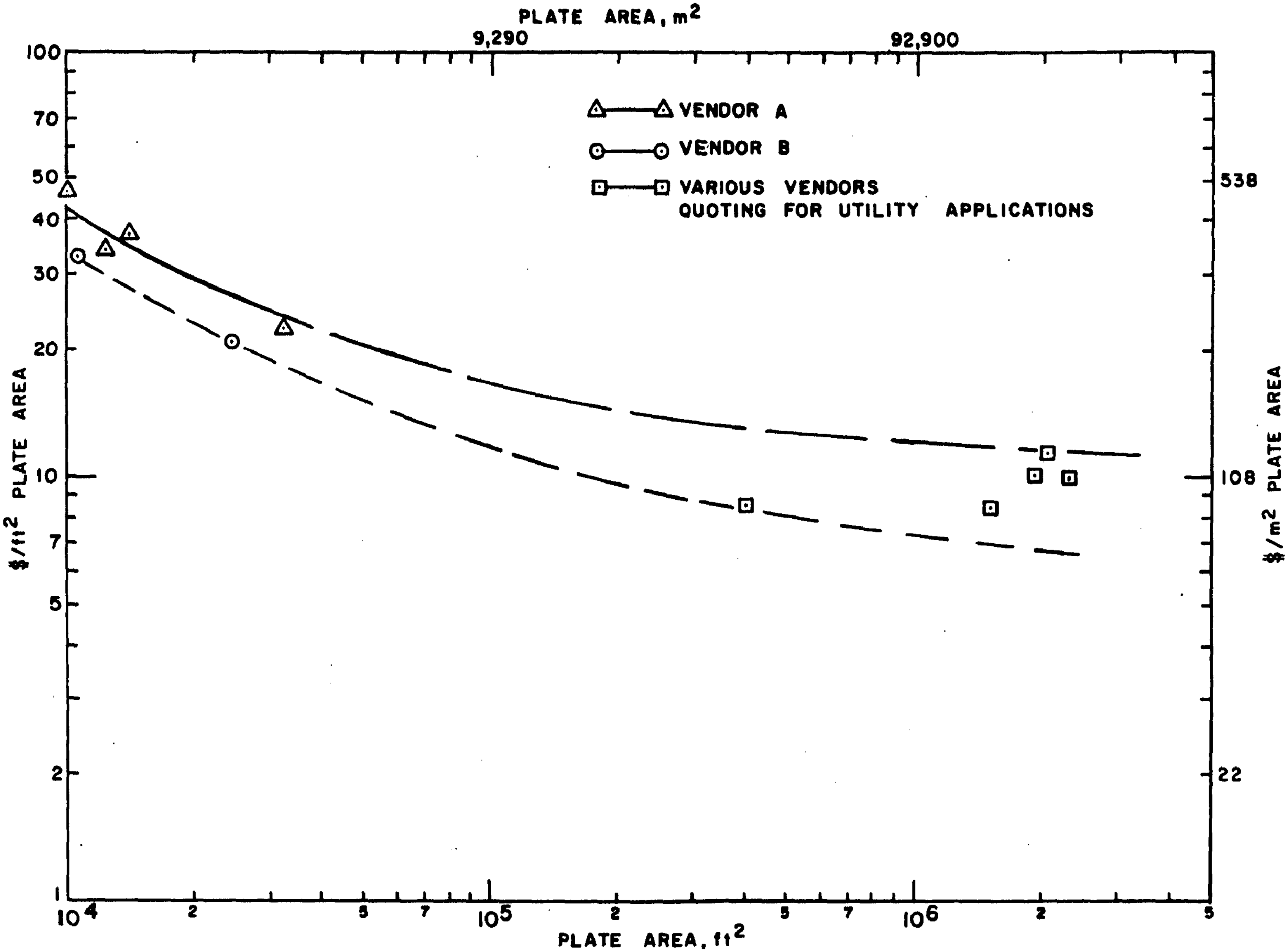

Figure 30. The capital cost of a precipitator as a function of size as reported by several manufacturers.[12]

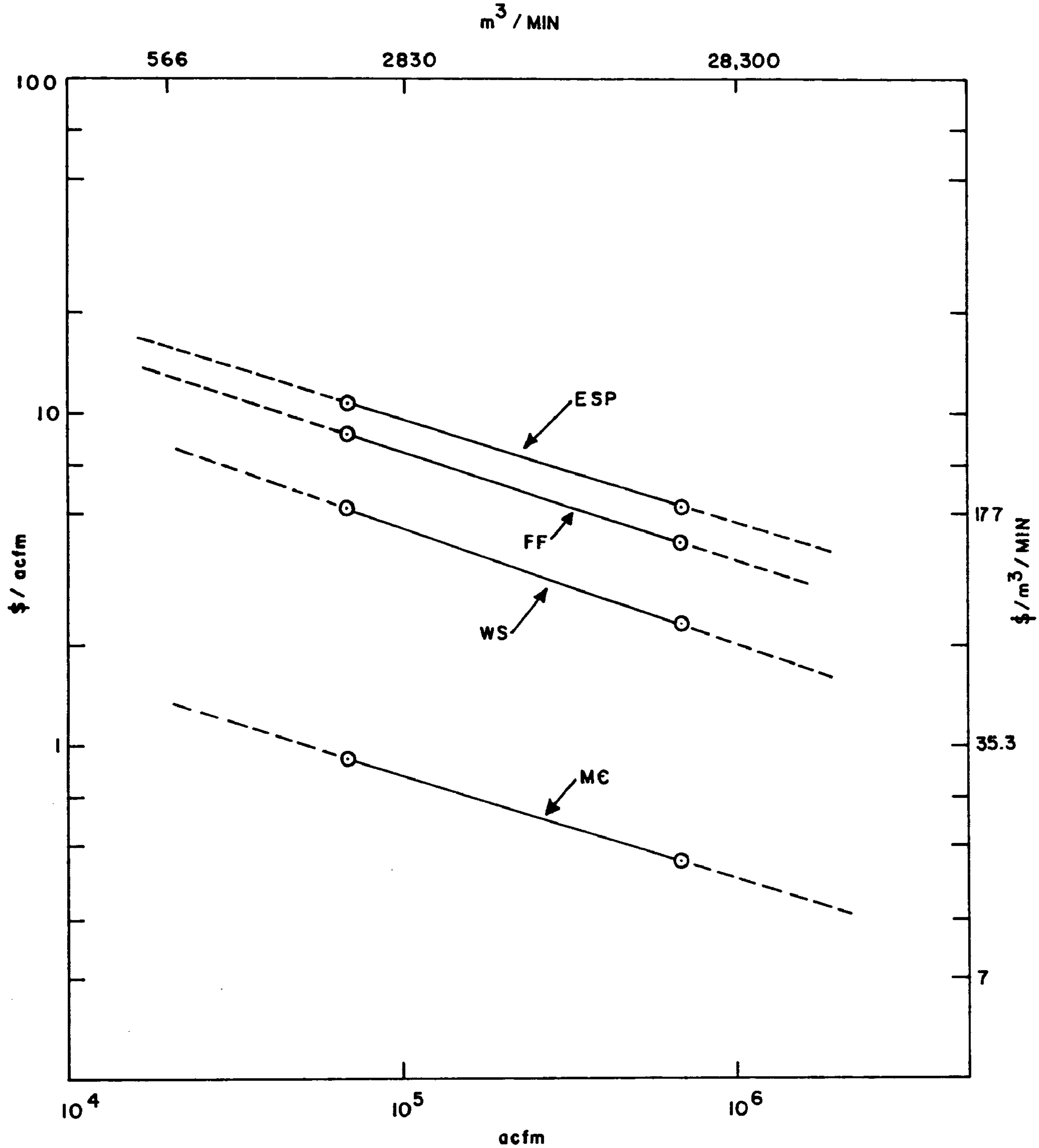

Figure 31. Capital cost of basic equipment (including installation) and auxiliaries as a function of system size (reported by Vendor A for a pulverized coal boiler).

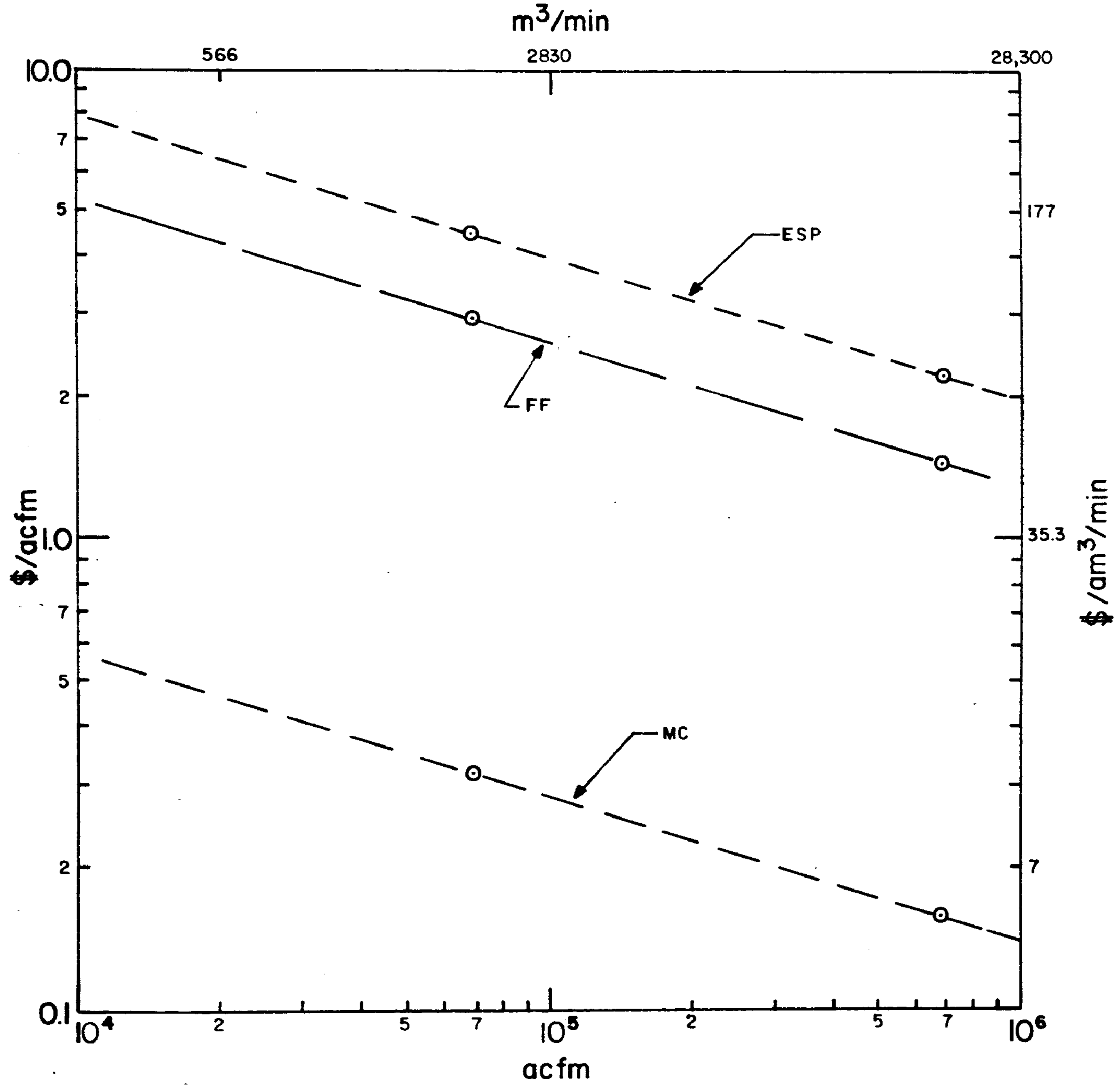

Figure 32. Installation cost as a function of system size (reported by Vendor A for a pulverized coal boiler).

and by the Department of Energy/Argonne National Laboratory were utilized to compute equipment costs for hot and cold precipitators, fabric filters, and wet scrubbers. These models were originally designed for large utility boilers and were modified by GCA to reflect key assumptions inherent in this study and current fabric costs of $\$7.00/m^2$ ($\$0.65/ft^2$) for 10 percent Teflon-coated glass fabric installed on a reverse air fabric filter.[14] The results (presented in earlier drafts of this report) were judged to underestimate the actual costs for particulate control and are not included in this final report.

The following sections discuss the estimating techniques provided by PEDCo.

4.1.6.1 Capital Costs--

Capital costs for particulate control systems are composed of direct and indirect costs incurred up to the successful commissioning date of the facility. Direct costs include basic and auxiliary equipment costs, the labor and material required to install the equipment, and land. Indirect costs are comprised of items such as engineering, construction, field expenses, construction fees, startup, performance or acceptance tests, contingencies, and working capital.

Equipment and related installation costs have been obtained from vendors and the technical literature. Values for indirect capital costs, which are based on various percentages provided by PEDCo, are listed below:

- Engineering - 10 percent of installed cost
- Construction and field expenses - 10 percent of installed cost
- Construction fees - 10 percent of installed cost
- Startup - 2 percent of installed cost

- Contingencies - 20 percent of direct and indirect costs
- Working capital - 25 percent of direct operating costs

It should be emphasized that these percentages are utilized for consistency only; realistically, each of these items would vary depending on the piece of control equipment used, the vendor's experience, and other site-specific factors.

The average cost of a performance test, based upon GCA experience, can range from \$2,000 to \$10,000. A value of \$5,000 has been used in all examples given in this report.

The cost of land required for a pollution control device, which is usually a small fraction of the overall costs, would probably be included in the land cost for the entire boiler facility. However, the costs given in this section have been based on a factor of 0.46 m^2 (5.0 ft^2) per 100 kW of capacity and a land cost of \$2.50 per m^2 (\$10,000 per acre).[15]

The total capital costs for the various systems presented subsequently are also expressed in terms of the volumetric flow rate for the purpose of comparison and to indicate the exponential increase in cost with decreasing size.

4.1.6.2 Annualized Costs--

Annual operating costs are made up of direct costs such as labor, supervision, replacement parts, energy costs (electrical) to run the equipment, waste disposal, and steam, water, or chemicals where required. In addition, overhead and capital charges are taken into consideration in computing a resultant annualized cost.

For all detailed cost estimates, operatling labor and supervision costs related to the control equipment are based upon the following factors derived from the IGCI study (Reference 8):

	ESP	FF and WS	MC
Operating labor man-hours per hour of operation	0.035	0.1	0.003
Supervision % of man-hours for operating labor	18	5	25

The cost for operating labor is taken as $12.02/man-hour and the cost for supervision as $15.63/man-hour as provided by PEDCo. Maintenance labor, materials, and replacement parts were taken as percentages of total equipment purchase price (excluding installation) as shown below:[16]

- Electrostatic precipitators - 2 percent
- Fabric filters - 2 percent
- Scrubbers - 13 percent
- Mechanical collectors - 1 percent (assumed)

Electricity costs were based on a unit cost of $0.0258 per kW hour (as provided by PEDCo) and electrical consumption figures calculated in Section 5.0, Table 60.

Water consumption by a scrubber is based on a water cost of $0.032/1000 liters ($0.12 per 1,000 gallons).

Fly ash disposal is assumed to take place at a hauling distance of 32 km (20 miles) and a unit cost of $1.38/1000 kg-km ($2.00/ton-mile), dry basis, for a total cost of $44.16/1000 kg ($40.00/ton).[17] (This value has been utilized by PEDCo in determining bottom ash disposal costs for the uncontrolled boilers).

Payroll overhead is taken as 30 percent of direct labor while plant overhead is taken at 26 percent of labor, materials, and maintenance. Overhead charges representing business expenses, rather than being charged directly to a particular part of the process, are added as a separate group. Such costs may include administrative, safety, legal, and medical services as well as employee fringe benefits and public relations.

The capital investment for a particulate collection system is generally translated into annual capital charges. General and administrative costs, taxes, and insurance combined are taken at 4 percent of depreciable investment or total turnkey cost.

The capital recovery factor (CRF) is a function of the annual interest rate and the expected equipment service life. Calculations are based on the following equation:

$$CRF = \frac{i\ (1+i)^n}{(1+i)^n - 1} \qquad (2)$$

where i = interest rate (decimal)
n = number of years

Equipment service lives (for accounting purposes) are taken at 20 years for precipitators, baghouses, and mechanical collectors, and 10 years for wet scrubbers.[18] Based on an annual interest rate of 10 percent, the capital recovery factor becomes 0.11746 for a 20-year service life and 0.16275 for a 10-year life. Total capital charges are therefore 15.75 percent (11.75 + 4.0) and 20.3 percent (16.3 + 4.0) of total turnkey cost, respectively. The total annualized cost of the pollution control device is therefore the sum of direct operating costs, overhead, and capital charges. For each estimate, unit costs are given in terms of the amount of pollutant removed (i.e., cost-effectiveness). Although this type of unit cost is an indicator of actual system cost in terms of pollutant removed, it is not directly applicable to control of fly ash since the collected material is thrown away. Also, this parameter must obviously increase when higher efficiencies are required for removal of the finer-sized, light-weight emissions. This definition of cost-effectiveness (showing the multitube cyclone to have the highest rating) would be better applied in situations where the collected material is recovered as a valuable product.

The detailed cost figures for 60 specific cases with the assumptions described previously are given in Tables 33 through 54. Capital investment and annualized costs for the same system are designated a and b, respectively.

Tables 33 through 41 and 47 through 54 contain costs developed by GCA in conjunction with costs supplied by various equipment suppliers.[19] For example, the vendor-supplied costs graphed in Figure 30 were used with plate area requirements calculated in Section 5.0 to arrive at installed cost figures. Tables 42 through 44 show cost figures developed by the Industrial Gas Cleaning Institute (IGCI),[20] which have been inflated to June 1978 costs and normalized to the extent possible so as to agree with the assumptions in this study. Tables 45 and 46 contain data provided by Vendor D.[21]

Table 35 shows cost information for a spreader stoker boiler controlled by an ESP and Table 36 shows the same boiler controlled by a mechanical collector. The vendor has stated that these two devices are to be used in series on this boiler to achieve the desired control efficiency. This is also true for the underfeed stoker boiler given in Tables 37 and 38. For these two boilers, labor and supervision, and waste disposal related costs have been included only on the precipitator cost sheet.

TABLE 33a. CAPITAL COSTS FOR A PULSE-JET FABRIC FILTER (AT THE STRINGENT LEVEL) INSTALLED ON A PULVERIZED COAL BOILER - 58.6 MW (200×10^6 Btu/hr) INPUT

EQUIPMENT COSTS	
Basic equipment (includes freight)	-
Required auxiliaries	-
Subtotal	388,500

INSTALLATION COSTS, DIRECT	
Foundations and supports	-
Ductwork	
Stack	
Piping	
Insulation	
Painting	
Electrical	
Subtotal	202,500

TOTAL DIRECT COSTS			
(equipment and installation)	591,000		
INSTALLATION COSTS, INDIRECT			
Engineering	59,100		
Construction and field expense	59,100		
Construction fees	59,100		
Startup	11,820		
Performance test	5,000		
Subtotal	194,120		
Contingencies	157,024		
TOTAL TURNKEY COSTS	942,144		
Land	230		
	3.5 percent S	0.9 percent S	0.6 percent S
Working Capital	44,449	27,553	30,284
GRAND TOTAL	986,823	969,927	972,658
$/m^3/hr	7.77	8.09	7.82
($/acfm)	13.19	13.74	13.29

TABLE 33b. ANNUALIZED COSTS FOR A PULSE-JET FABRIC FILTER (AT THE STRINGENT LEVEL) INSTALLED ON A PULVERIZED COAL BOILER - 58.6 MW (200×10^6 Btu/hr) INPUT

			3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS					
Direct labor	6,318				
Supervision	411				
Maintenance labor, materials and parts	7,770				
Electricity			12,937	12,232	12,638
Steam	-				
Cooling water	-				
Process water	-				
Fuel	-				
Waste disposal			150,360	83,480	94,000
Chemicals	-				
TOTAL DIRECT COSTS			177,796	110,211	121,137
OVERHEAD					
Payroll	2,019				
Plant	2,020				
TOTAL OVERHEAD	4,039				
CAPITAL CHARGES					
G&A, taxes and insurance		37,686			
Capital recovery factor		110,702			
TOTAL CAPITAL CHARGES		148,388			
TOTAL ANNUALIZED COSTS			330,223	262,638	273,564
$/$10^3$ kg removed			96.64	138.42	128.05
($/ton removed)			(87.85)	(125.84)	(116.41)

TABLE 34a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A PULVERIZED COAL BOILER - 58.6 MW (200 × 10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	228,883 (3.5% S)	Stack	-
	415,248 (0.9% S)	Piping	-
	416,869 (0.6% S)	Insulation	-
		Painting	-
		Electrical	-
		Subtotal	171,662 (3.5% S)
			311,436 (0.9% S)
			312,651 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	400,545	726,684	729,520
INSTALLATION COSTS, INDIRECT			
Engineering	40,055	72,668	72,952
Construction and field expense	40,055	72,668	72,952
Construction fees	40,055	72,668	72,952
Startup	8,011	14,534	14,590
Performance test	5,000	5,000	5,000
Subtotal	133,176	237,538	238,446
Contingencies	106,744	192,844	193,593
TOTAL TURNKEY COSTS	640,465	1,157,066	1,161,559
Land	230	230	230
Working Capital	39,952	25,876	29,168
GRAND TOTAL	680,647	1,183,172	1,190,957
$/m³/hr	5.36	9.86	9.58
($/acfm)	(9.10)	(16.76)	(16.27)

TABLE 34b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A PULVERIZED COAL BOILER - 58.6 MW (200 × 10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		4,578	8,305	8,337
Electricity		3,580	10,469	13,086
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		148,920	82,000	92,520
Chemicals				
TOTAL DIRECT COSTS		159,807	103,503	116,672
OVERHEAD				
Payroll	819			
Plant		1,190	2,159	2,168
TOTAL OVERHEAD		2,009	2,978	2,987
CAPITAL CHARGES				
G&A, taxes and insurance		25,619	46,283	46,462
Capital recovery factor		75,255	135,955	136,483
TOTAL CAPITAL CHARGES		100,874	182,238	182,945
TOTAL ANNUALIZED COSTS		262,690	288,719	302,604
$/$10^3$ kg removed		77.61	154.92	143.91
($/ton removed)		(70.56)	(140.84)	(130.83)

TABLE 35a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	188,280 (3.5% S)	Stack	-
	374,799 (0.9% S)	Piping	-
	400,266 (0.6% S)	Insulation	-
		Painting	-
		Electrical	-
		Subtotal	141,210 (3.5% S)
			281,099 (0.9% S)
			300,200 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	329,490	655,898	700,466
INSTALLATION COSTS, INDIRECT			
Engineering	32,949	65,590	70,047
Construction and field expense	32,949	65,590	70,047
Construction fees	32,949	65,590	70,047
Startup	6,590	13,118	14,009
Performance test	5,000	5,000	5,000
Subtotal	110,437	214,888	229,150
Contingencies	87,985	174,157	185,923
TOTAL TURNKEY COSTS	527,912	1,044,943	1,115,539
Land	172	172	172
Working Capital	25,010	17,109	19,368
GRAND TOTAL	553,094	1,062,224	1,135,079
$/m^3/hr	5.03	10.28	10.64
($/acfm)	(8.54)	(17.47)	(18.07)

TABLE 35b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150 × 10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		3,766	7,496	8,005
Electricity		2,983	8,570	10,659
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		90,560	49,640	56,080
Chemicals				
TOTAL DIRECT COSTS		100,038	68,435	77,473
OVERHEAD				
Payroll	819			
Plant		979	1,949	2,081
TOTAL OVERHEAD		1,798	2,768	2,900
CAPITAL CHARGES				
G&A, taxes and insurance		21,116	41,798	44,622
Capital recovery factor		62,030	122,781	131,076
TOTAL CAPITAL CHARGES		83,146	164,579	175,698
TOTAL ANNUALIZED COSTS		184,982	235,782	256,071
$/$10^3$ kg removed		101.22	229.28	219.01
($/ton removed)		(92.01)	(208.44)	(199.10)

Note: Cost-effectiveness is calculated by including the annualized cost of the mechanical collector given in Table 36b since these two collectors are to be used in series.

TABLE 36a. CAPITAL COSTS FOR A MECHANICAL COLLECTOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150 × 10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	37,300	Stack	-
		Piping	-
		Insulation	-
		Painting	-
		Electrical	-
		Subtotal	20,500

		3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS				
(equipment and installation)	57,800			
INSTALLATION COSTS, INDIRECT				
Engineering	5,780			
Construction and field expense	5,780			
Construction fees	5,780			
Startup	1,156			
Performance test	5,000			
Subtotal	23,496			
Contingencies	16,259			
TOTAL TURNKEY COSTS	97,555			
Land	-			
Working Capital		2,814	2,644	2,712
GRAND TOTAL		100,369	100,199	100,267
$/m³/hr		0.91	0.97	0.94
($/acfm)		(1.55)	(1.65)	(1.60)

TABLE 36b. ANNUALIZED COSTS FOR A MECHANICAL COLLECTOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150 × 10^6 Btu/hr) INPUT

			3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS					
Direct labor	-				
Supervision	-				
Maintenance labor, materials and parts	373				
Electricity			7,503	7,051	7,232
Steam					
Cooling water	-				
Process water	-				
Fuel	-				
Waste disposal			-	-	-
Chemicals	-				
TOTAL DIRECT COSTS			7,876	7,424	7,605
OVERHEAD					
Payroll	-				
Plant	97				
TOTAL OVERHEAD	97				
CAPITAL CHARGES					
G&A, taxes and insurance		3,902			
Capital recovery factor		11,463			
TOTAL CAPITAL CHARGES		15,365			
TOTAL ANNUALIZED COSTS			23,338	22,886	23,067

TABLE 37a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER - 8.8 MW (30×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		
Basic equipment (includes freight)	-	
Required auxiliaries	-	
Subtotal	31,686 (3.5% S)	
	84,315 (0.9% S)	
	100,774 (0.6% S)	

INSTALLATION COSTS, DIRECT		
Foundations and supports	-	
Ductwork	-	
Stack	-	
Piping	-	
Insulation	-	
Painting	-	
Electrical	-	
Subtotal	23,764 (3.5% S)	
	63,237 (0.9% S)	
	75,581 (0.6% S)	

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS			
(equipment and installation)	55,450	147,552	176,355
INSTALLATION COSTS, INDIRECT			
Engineering	5,545	14,755	17,636
Construction and field expense	5,545	14,755	17,636
Construction fees	5,545	14,755	17,636
Startup	1,109	2,951	3,527
Performance test	5,000	5,000	5,000
Subtotal	22,744	52,216	61,435
Contingencies	15,639	39,954	47,558
TOTAL TURNKEY COSTS	93,833	239,722	285,348
Land	34	34	34
Working Capital	2,650	2,329	2,603
GRAND TOTAL	96,517	242,085	286,985
$/m^3/hr	4.40	11.68	13.56
($/acfm)	(7.48)	(19.84)	(23.04)

TABLE 37b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER – 8.8 MW (30×10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		634	1,686	2,015
Electricity		475	1,261	1,546
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		6,760	3,640	4,120
Chemicals				
TOTAL DIRECT COSTS		10,598	9,316	10,410
OVERHEAD				
Payroll	819			
Plant		165	438	524
TOTAL OVERHEAD		984	1,257	1,343
CAPITAL CHARGES				
G&A, taxes and insurance		3,753	9,589	11,414
Capital recovery factor		11,025	28,167	33,528
TOTAL CAPITAL CHARGES		14,778	37,756	44,942
TOTAL ANNUALIZED COSTS		26,360	48,329	56,695
$\$/10^3$ kg removed		235.13	701.35	709.38
($/ton removed)		(213.76)	(637.59)	(644.89)

Note: Cost-effectiveness is calculated by including the annualized cost of the mechanical collector given in Table 38b since these two collectors are to be used in series.

TABLE 38a. CAPITAL COSTS FOR A MECHANICAL COLLECTOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER - 8.8 MW (30×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	18,000	Stack	-
		Piping	-
		Insulation	-
		Painting	-
		Electrical	-
		Subtotal	10,500

		3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	28,500			
INSTALLATION COSTS, INDIRECT				
Engineering	2,850			
Construction and field expense	2,850			
Construction fees	2,850			
Startup	570			
Performance test	5,000			
Subtotal	14,120			
Contingencies	8,524			
TOTAL TURNKEY COSTS	51,144			
Land	-			
Working Capital		601	574	588
GRAND TOTAL		51,745	51,718	51,732
$\$/m^3/hr$		2.36	2.50	2.44
(\$/acfm)		(4.01)	(4.24)	(4.14)

TABLE 38b. ANNUALIZED COSTS FOR A MECHANICAL COLLECTOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER - 8.8 MW (30×10^6 Btu/hr) INPUT

			3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS					
Direct labor	-				
Supervision	-				
Maintenance labor, materials and parts	180				
Electricity			1,483	1,410	1,447
Steam					
Cooling water					
Process water					
Fuel					
Waste disposal			-	-	-
Chemicals					
TOTAL DIRECT COSTS			1,663	1,590	1,627
OVERHEAD					
Payroll	-				
Plant	47				
TOTAL OVERHEAD	47				
CAPITAL CHARGES					
G&A, taxes and insurance		2,046			
Capital recovery factor		6,009			
TOTAL CAPITAL CHARGES		8,055			
TOTAL ANNUALIZED COSTS			9,765	9,692	9,729

TABLE 39a. CAPITAL COSTS FOR A PULSE-JET FABRIC FILTER (AT THE STRINGENT LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	283,000	Stack	-
		Piping	-
		Insulation	-
		Painting	-
		Electrical	-
		Subtotal	196,500

		3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	479,500			
INSTALLATION COSTS, INDIRECT				
Engineering	47,950			
Construction and field expense	47,950			
Construction fees	47,950			
Startup	9,590			
Performance test	5,000			
Subtotal	158,440			
Contingencies	127,588			
TOTAL TURNKEY COSTS	765,528			
Land	172			
Working Capital		28,808	18,408	20,103
GRAND TOTAL		794,508	784,108	785,803
$/m³/hr		7.22	7.59	7.36
($/acfm)		(12.26)	(12.90)	(12.51)

TABLE 39b. ANNUALIZED COSTS FOR A PULSE-JET FABRIC FILTER (AT THE STRINGENT LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150 × 10^6 Btu/hr) INPUT

			3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS					
Direct labor	6,318				
Supervision	411				
Maintenance labor, materials and parts	5,660				
Electricity			11,201	10,523	10,862
Steam	-				
Cooling water	-				
Process water	-				
Fuel	-				
Waste disposal			91,640	50,720	57,160
Chemicals					
TOTAL DIRECT COSTS			115,230	73,632	80,411
OVERHEAD					
Payroll	2,019				
Plant	1,472				
TOTAL OVERHEAD	3,491				
CAPITAL CHARGES					
G&A, taxes and insurance		30,621			
Capital recovery factor		89,950			
TOTAL CAPITAL CHARGES		120,571			
TOTAL ANNUALIZED COSTS			239,292	197,694	204,473
\$/10^3 kg removed			114.90	171.50	157.40
(\$/ton removed)			(104.45)	(155.91)	(143.09)

TABLE 40a. CAPITAL COSTS FOR A PULSE-JET FABRIC FILTER (AT THE STRINGENT LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER - 8.8 MW (30×10^6 Btu/hr) INPUT

EQUIPMENT COSTS	
Basic equipment (includes freight)	-
Required auxiliaries	-
Subtotal	98,500

INSTALLATION COSTS, DIRECT	
Foundations and supports	-
Ductwork	-
Stack	-
Piping	-
Insulation	-
Painting	-
Electrical	-
Subtotal	48,000

		3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS				
(equipment and installation)	146,500			
INSTALLATION COSTS, INDIRECT				
Engineering	14,650			
Construction and field expense	14,650			
Construction fees	14,650			
Startup	2,930			
Performance test	5,000			
Subtotal	51,880			
Contingencies	39,676			
TOTAL TURNKEY COSTS	238,056			
Land	34			
Working Capital		4,481	3,674	3,807
GRAND TOTAL		242,571	241,764	241,897
$/m³/hr		11.07	11.67	11.39
($/acfm)		(18.80)	(19.82)	(19.35)

TABLE 40b. ANNUALIZED COSTS FOR A PULSE-JET FABRIC FILTER (AT THE STRINGENT LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER - 8.8 MW (30×10^6 Btu/hr) INPUT

			3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS					
Direct labor	6,318				
Supervision	411				
Maintenance labor, materials and parts	1,970				
Electricity			2,224	2,115	2,170
Steam	-				
Cooling water	-				
Process water	-				
Fuel	-				
Waste disposal			7,000	3,880	4,360
Chemicals	-				
TOTAL DIRECT COSTS			17,923	14,694	15,229
OVERHEAD					
Payroll	2,019				
Plant	512				
TOTAL OVERHEAD	2,531				
CAPITAL CHARGES					
G&A, taxes and insurance		9,522			
Capital recovery factor		27,972			
TOTAL CAPITAL CHARGES		37,494			
TOTAL ANNUALIZED COSTS			57,948	54,719	55,254
$\$/10^3$ kg removed			364.24	620.52	557.61
(\$/ton removed)			(331.13)	(564.11)	(506.92)

TABLE 41a. CAPITAL COSTS FOR A FLOODED DISC SCRUBBER (AT THE INTERMEDIATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT		
Basic equipment (includes freight)	-	Foundations and supports	-	
Required auxiliaries	-	Ductwork	-	
Subtotal	189,714	Stack	-	
		Piping	-	
		Insulation	-	
		Painting	-	
		Electrical	-	
		Subtotal	142,286	

		3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS				
(equipment and installation)	332,000			
INSTALLATION COSTS, INDIRECT				
Engineering	33,200			
Construction and field expense	33,200			
Construction fees	33,200			
Startup	6,640			
Performance test	5,000			
Subtotal	111,240			
Contingencies	88,648			
TOTAL TURNKEY COSTS	531,888			
Land	200			
Working Capital		40,560	30,330	31,940
GRAND TOTAL		572,648	562,418	564,028
$\$/m^3/hr$		5.20	5.44	5.29
(\$/acfm)		(8.84)	(9.25)	(8.98)

TABLE 41b. ANNUALIZED COSTS FOR A FLOODED DISC SCRUBBER (AT THE INTERMEDIATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150×10^6 Btu/hr) INPUT

			3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS					
Direct labor	6,318				
Supervision	411				
Maintenance labor, materials and parts	24,663				
Electricity			23,731	23,731	23,731
Steam	-				
Cooling water	-				
Process water			16,556	16,556	16,556
Fuel	-				
Waste disposal			90,560	49,640	56,080
Chemicals	-				
TOTAL DIRECT COSTS			162,239	121,319	127,759
OVERHEAD					
Payroll	2,019				
Plant	6,412				
TOTAL OVERHEAD	8,431				
CAPITAL CHARGES					
G&A, taxes and insurance		21,276			
Capital recovery factor		86,698			
TOTAL CAPITAL CHARGES		107,974			
TOTAL ANNUALIZED COSTS			278,644	237,724	244,164
$\$/10^3$ kg removed			135.39	210.72	191.57
($/ton removed)			(123.08)	(191.56)	(174.15)

TABLE 42a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 45 MW (154×10^6 Btu/hr) INPUT (IGCI DATA)

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	235,758*	Foundations and supports	14,657
Required auxiliaries	86,059	Ductwork	67,413
Subtotal	321,817	Stack	10,816
		Piping	108,237
		Insulation	64,427
		Painting	2,314
		Electrical	37,701
		Subtotal	305,565

	0.8% S
TOTAL DIRECT COSTS (equipment and installation)	627,382
INSTALLATION COSTS, INDIRECT	
Engineering	14,964
Construction and field expense	31,342
Construction fees	1,026
Startup	5,904
Performance test	8,000
Subtotal	61,236
Contingencies	21,005
TOTAL TURNKEY COSTS	709,623
Land	172
Working Capital	23,319
GRAND TOTAL	733,114
$/m^3/hr	5.19
($/acfm)	(8.82)

*SCA = 47 m^2/m^3/sec (239 ft^2/1000 acfm)

TABLE 42b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 45 MW (154×10^6 Btu/hr) INPUT (IGCI DATA)

			0.8 percent S
DIRECT COSTS			
Direct labor	2,344		
Supervision	508		
Maintenance labor	3,482		
Materials	171		
Parts	878		
Electricity			20,812
Steam	-		
Cooling water	-		
Process water	-		
Fuel	-		
Waste disposal			60,087
Chemicals	-		
TOTAL DIRECT COSTS			88,282
OVERHEAD			
Payroll	536		
Plant	2,781		
TOTAL OVERHEAD	3,317		
CAPITAL CHARGES			
G&A, taxes and insurance		-	
Capital recovery factor		-	
TOTAL CAPITAL CHARGES		120,603	
TOTAL ANNUALIZED COSTS			212,202
$/10³ kg removed			155.41
($/ton removed)			(141.28)

TABLE 43a. CAPITAL COSTS FOR A PULSE-JET FABRIC FILTER (AT THE STRINGENT LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 55 MW (188 × 10^6 Btu/hr) INPUT (IGCI DATA)

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	226,538*	Foundations and supports	17,574
Required auxiliaries	46,409	Ductwork	67,413
Subtotal	272,947	Stack	10,827
		Piping	4,570
		Insulation	63,504
		Painting	3,077
		Electrical	17,791
		Other	35,433
		Subtotal	220,189

	0.8% S
TOTAL DIRECT COSTS (equipment and installation)	493,136
INSTALLATION COSTS, INDIRECT	
Engineering	17,449
Construction and field expense	13,278
Construction fees	4,251
Startup	4,046
Performance test	5,129
Subtotal	44,153
Contingencies	8,126
TOTAL TURNKEY COSTS	545,415
Land	172
Working Capital	35,321
GRAND TOTAL	580,908
$/m³/hr	3.93
($/acfm)	(6.67)

*A/C = 1.5/1 (m/min) (4.8/1 - ft/min)

TABLE 43b. ANNUALIZED COSTS FOR A PULSE-JET FABRIC FILTER (AT THE STRINGENT LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 55 MW (188×10^6 Btu/hr) INPUT (IGCI DATA)

			0.8 percent S
DIRECT COSTS			
Direct labor	9,652		
Supervision	436		
Maintenance labor	5,764		
Materials	2,718		
Parts	27,250		
Electricity			20,382
Steam	-		
Cooling water	-		
Process water	-		
Fuel	-		
Waste disposal			75,080
Chemicals	-		
TOTAL DIRECT COSTS			141,282
OVERHEAD			
Payroll	1,909		
Plant	8,371		
TOTAL OVERHEAD	10,280		
CAPITAL CHARGES			
G&A, taxes and insurance		-	
Capital recovery factor		-	
TOTAL CAPITAL CHARGES		92,715	
TOTAL ANNUALIZED COSTS			244,277
$/$10^3$ kg removed			143.16
($/ton removed)			(130.14)

TABLE 44a. CAPITAL COSTS FOR A MECHANICAL COLLECTOR (AT THE MODERATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 40 MW (137×10^6 Btu/hr) INPUT (IGCI DATA)

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	58,182	Foundations and supports	10,257
Required auxiliaries	11,682	Ductwork	60,643
Subtotal	69,864	Stack	9,984
		Piping	4,445
		Insulation	7,796
		Painting	137
		Electrical	9,118
		Subtotal	102,380

	0.8% S
TOTAL DIRECT COSTS (equipment and installation)	172,244
INSTALLATION COSTS, INDIRECT	
Engineering	2,279
Construction and field expense	5,129
Construction fees	2,165
Startup	1,140
Performance test	2,279
Subtotal	12,992
Contingencies	-
TOTAL TURNKEY COSTS	185,236
Land	
Working Capital	40,844
GRAND TOTAL	226,080
$/m³/hr	1.81
($/acfm)	(3.08)

TABLE 44b. ANNUALIZED COSTS FOR A MECHANICAL COLLECTOR (AT THE MODERATE LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 40 MW (137×10^6 Btu/hr) INPUT (IGCI DATA)

			0.8 percent S
DIRECT COSTS			
Direct labor	120		
Supervision	39		
Maintenance labor	351		
Materials	-		
Parts	832		
Electricity			14,474*
Steam	-		
Cooling water	-		
Process water	-		
Fuel	-		
Waste disposal			147,560†
Chemicals			
TOTAL DIRECT COSTS			163,376
OVERHEAD			
Payroll	34		
Plant	160		
TOTAL OVERHEAD	194		
CAPITAL CHARGES			
G&A, taxes and insurance		-	
Capital recovery factor		-	
TOTAL CAPITAL CHARGES		31,490	
TOTAL ANNUALIZED COSTS			195,060
$\$/10^3$ kg removed			58.16
($/ton removed)			(52.88)

*ΔP = 1.5 kPa (6.2 in. W.C.)

†A high waste disposal cost is indicated since just over 635 kg/hr (1,400 lb/hr) are removed by the collector.

TABLE 45a. CAPITAL COSTS FOR A TWO-STAGE IONIZING WET SCRUBBER (AT THE STRINGENT LEVEL) INSTALLED ON A CHAIN GRATE STOKER BOILER - 22 MW (75×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	256,500	Stack	-
		Piping	-
		Insulation	-
		Painting	-
		Electrical	-
		Subtotal	359,100

		3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	615,600			
INSTALLATION COSTS, INDIRECT				
Engineering	61,560			
Construction and field expense	61,560			
Construction fees	61,560			
Startup	12,312			
Performance test	5,000			
Subtotal	201,992			
Contingencies	163,518			
TOTAL TURNKEY COSTS	981,110			
Land	86			
Working Capital		18,865	16,844	17,178
GRAND TOTAL		1,000,061	998,040	998,374
$\$/m^3/hr$		18.22	19.52	18.72
(\$/acfm)		(30.96)	(33.16)	(31.80)

TABLE 45b. ANNUALIZED COSTS FOR A TWO-STAGE IONIZING WET SCRUBBER (AT THE STRINGENT LEVEL) INSTALLED ON A CHAIN GRATE STOKER BOILER - 22 MW (75×10^6 Btu/hr) INPUT

			3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS					
Direct labor	6,318				
Supervision	411				
Maintenance labor, materials and parts	33,345				
Electricity			3,716	3,471	3,607
Steam					
Cooling water					
Process water	14,190				
Fuel	-				
Waste disposal			17,480	9,640	10,840
Chemicals	-				
TOTAL DIRECT COSTS			75,460	67,375	68,711
OVERHEAD					
Payroll	2,019				
Plant	8,670				
TOTAL OVERHEAD	10,689				
CAPITAL CHARGES					
G&A, taxes and insurance		39,244			
Capital recovery factor		159,921			
TOTAL CAPITAL CHARGES		199,165			
TOTAL ANNUALIZED COSTS			285,314	277,229	278,565
$/$10^3$ kg removed			718.18	1265.36	1130.71
($/ton removed)			(652.89)	(1150.33)	(1027.92)

TABLE 46a. CAPITAL COSTS FOR A ONE-STAGE IONIZING WET SCRUBBER (AT THE INTERMEDIATE LEVEL) INSTALLED ON A CHAIN GRATE STOKER BOILER - 22 MW (75 × 10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	132,200	Stack	-
		Piping	-
		Insulation	-
		Painting	-
		Electrical	-
		Subtotal	162,400

		3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS				
(equipment and installation)	294,600			
INSTALLATION COSTS, INDIRECT				
Engineering	29,460			
Construction and field expense	29,460			
Construction fees	29,460			
Startup	5,892			
Performance test	5,000			
Subtotal	99,272			
Contingencies	78,774			
TOTAL TURNKEY COSTS	472,646			
Land	86			
Working Capital		12,447	10,457	10,774
GRAND TOTAL		485,179	483,189	483,506
$/m^3/hr		8.84	9.45	9.06
($/acfm)		(15.02)	(16.05)	(15.40)

TABLE 46b. ANNUALIZED COSTS FOR A ONE-STAGE IONIZING WET SCRUBBER (AT THE INTERMEDIATE LEVEL) INSTALLED ON A CHAIN GRATE STOKER BOILER - 22 MW (75×10^6 Btu/hr) INPUT

			3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS					
Direct labor	6,318				
Supervision	411				
Maintenance labor, materials and parts	17,186				
Electricity			1,858	1,736	1,804
Steam	-				
Cooling water	-				
Process water	7,095				
Fuel	-				
Waste disposal			16,920	9,080	10,280
Chemicals	-				
TOTAL DIRECT COSTS			49,788	41,826	43,094
OVERHEAD					
Payroll	2,019				
Plant	4,468				
TOTAL OVERHEAD	6,487				
CAPITAL CHARGES					
G&A, taxes and insurance		18,906			
Capital recovery factor		77,041			
TOTAL CAPITAL CHARGES		95,947			
TOTAL ANNUALIZED COSTS			152,222	144,260	145,528
$/10^3 kg removed			395.85	699.06	622.89
($/ton removed)			(359.86)	(635.51)	(566.26)

TABLE 47a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE STRINGENT LEVEL) INSTALLED ON A PULVERIZED COAL BOILER - 58.6 MW (200×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		**INSTALLATION COSTS, DIRECT**	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	260,000 (3.5% S)	Stack	-
	432,400 (0.9% S)	Piping	-
	448,365 (0.6% S)	Insulation	-
		Painting	-
		Electrical	-
		Subtotal	194,800 (3.5% S)
			324,246 (0.9% S)
			336,273 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	454,800	756,646	784,638
INSTALLATION COSTS, INDIRECT			
Engineering	45,480	75,665	78,464
Construction and field expense	45,480	75,665	78,464
Construction fees	45,480	75,665	78,464
Startup	9,096	15,133	15,693
Performance test	5,000	5,000	5,000
Subtotal	150,536	247,128	256,085
Contingencies	121,067	200,755	208,145
TOTAL TURNKEY COSTS	726,403	1,204,529	1,248,868
Land	230	230	230
Working Capital	40,647	27,081	30,628
GRAND TOTAL	767,280	1,231,840	1,279,726
$/m^3/hr	6.04	10.27	10.29
($/acfm)	(10.26)	(17.45)	(17.48)

TABLE 47b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE STRINGENT LEVEL) INSTALLED ON A PULVERIZED COAL BOILER - 58.6 MW (200 × 10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		5,200	8,648	8,967
Electricity		4,300	13,466	16,815
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		150,360	83,480	94,000
Chemicals				
TOTAL DIRECT COSTS		162,589	108,323	122,511
OVERHEAD				
Payroll	819			
Plant		1,352	2,248	2,331
TOTAL OVERHEAD		2,171	3,067	3,150
CAPITAL CHARGES				
G&A, taxes and insurance		29,056	48,181	49,955
Capital recovery factor		85,352	141,532	146,742
TOTAL CAPITAL CHARGES		114,408	189,713	196,697
TOTAL ANNUALIZED COSTS		279,168	301,103	322,358
\$/10^3 kg removed		81.70	158.71	150.89
(\$/ton removed)		(74.27)	(144.28)	(137.17)

TABLE 48a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE STRINGENT LEVEL) INSTALLED ON A SPREADER STOKER BOILER – 44 MW (150×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	228,600 (3.5% S)	Stack	-
	407,800 (0.9% S)	Piping	-
	410,170 (0.6% S)	Insulation	-
		Painting	-
		Electrical	-
		Subtotal	171,492 (3.5% S)
			305,850 (0.9% S)
			307,630 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	400,092	713,650	717,800
INSTALLATION COSTS, INDIRECT			
Engineering	40,009	71,365	71,780
Construction and field expense	40,009	71,365	71,780
Construction fees	40,009	71,365	71,780
Startup	8,002	14,273	14,356
Performance test	5,000	5,000	5,000
Subtotal	133,029	233,368	234,696
Contingencies	106,624	189,404	190,499
TOTAL TURNKEY COSTS	639,745	1,136,422	1,142,995
Land	172	172	172
Working Capital	25,641	18,195	20,484
GRAND TOTAL	665,558	1,154,789	1,163,651
$\$/m^3/hr$	6.04	11.18	10.91
($/acfm)	(10.27)	(18.99)	(18.53)

TABLE 48b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE STRINGENT LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150×10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		4,572	8,156	8,203
Electricity		3,621	11,174	13,845
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		91,640	50,720	57,160
Chemicals				
TOTAL DIRECT COSTS		102,562	72,779	81,937
OVERHEAD				
Payroll	819			
Plant		1,189	2,121	2,133
TOTAL OVERHEAD		2,008	2,940	2,952
CAPITAL CHARGES				
G&A, taxes and insurance		25,590	45,457	45,720
Capital recovery factor		75,170	133,530	134,302
TOTAL CAPITAL CHARGES		100,760	178,987	180,022
TOTAL ANNUALIZED COSTS		205,330	254,706	264,911
$\$/10^3$ kg removed		98.58	220.96	203.92
($/ton removed)		(89.62)	(200.87)	(185.38)

TABLE 49a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE STRINGENT LEVEL) INSTALLED ON A CHAIN GRATE STOKER BOILER - 22 MW (75×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	106,313 (3.5% S)	Stack	-
	256,960 (0.9% S)	Piping	-
	295,529 (0.6% S)	Insulation	-
		Painting	-
		Electrical	-
		Subtotal	79,735 (3.5% S)
			192,720 (0.9% S)
			221,647 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	186,048	449,680	517,176
INSTALLATION COSTS, INDIRECT			
Engineering	18,605	44,968	51,718
Construction and field expense	18,605	44,968	51,718
Construction fees	18,605	44,968	51,718
Startup	3,721	8,994	10,344
Performance test	5,000	5,000	5,000
Subtotal	64,536	148,898	170,498
Contingencies	50,117	119,716	137,535
TOTAL TURNKEY COSTS	300,701	718,293	825,208
Land	86	86	86
Working Capital	5,964	5,489	6,257
GRAND TOTAL	306,751	723,868	831,551
$/m^3/hr	5.59	14.16	15.59
($/acfm)	(9.50)	(24.05)	(26.48)

TABLE 49b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE STRINGENT LEVEL) INSTALLED ON A CHAIN GRATE STOKER BOILER - 22 MW (75×10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		2,126	5,139	5,911
Electricity		1,519	4,448	5,546
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		17,480	9,640	10,840
Chemicals				
TOTAL DIRECT COSTS		23,854	21,956	25,026
OVERHEAD				
Payroll	819			
Plant		553	1,336	1,537
TOTAL OVERHEAD		1,372	2,155	2,356
CAPITAL CHARGES				
G&A, taxes and insurance		12,028	28,732	33,008
Capital recovery factor		35,332	84,399	96,962
TOTAL CAPITAL CHARGES		47,360	113,131	129,970
TOTAL ANNUALIZED COSTS		72,586	137,242	157,352
$\$/10^3$ kg removed		182.71	626.42	638.69
($/ton removed)		(166.10)	(569.47)	(580.63)

TABLE 50a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE STRINGENT LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER - 8.8 MW (30×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	44,229 (3.5% S)	Stack	-
	122,388 (0.9% S)	Piping	-
	147,060 (0.6% S)	Insulation	-
		Painting	-
		Electrical	-
		Subtotal	33,171 (3.5% S)
			91,792 (0.9% S)
			110,295 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS			
(equipment and installation)	77,400	214,180	257,355
INSTALLATION COSTS, INDIRECT			
Engineering	7,740	21,418	25,736
Construction and field expense	7,740	21,418	25,736
Construction fees	7,740	21,418	25,736
Startup	1,548	4,284	5,147
Performance test	5,000	5,000	5,000
Subtotal	29,768	73,538	87,355
Contingencies	21,434	57,544	68,942
TOTAL TURNKEY COSTS	128,602	345,262	413,652
Land	34	34	34
Working Capital	2,799	2,705	3,050
GRAND TOTAL	131,435	348,001	416,736
$/m^3/hr	6.00	16.79	19.62
($/acfm)	(10.19)	(28.52)	(33.34)

TABLE 50b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE STRINGENT LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER - 8.8 MW (30×10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		885	2,448	2,941
Electricity		583	1,763	2,170
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		7,000	3,880	4,360
Chemicals				
TOTAL DIRECT COSTS		11,197	10,820	12,200
OVERHEAD				
Payroll	518			
Plant		230	636	765
TOTAL OVERHEAD		1,049	1,455	1,584
CAPITAL CHARGES				
G&A, taxes and insurance		5,144	13,810	16,546
Capital recovery factor		15,111	40,568	48,604
TOTAL CAPITAL CHARGES		20,255	54,378	65,150
TOTAL ANNUALIZED COSTS		32,501	66,653	78,934
$\$/10^3$ kg removed		204.29	755.85	796.59
($/ton removed)		(185.72)	(687.14)	(724.17)

TABLE 51a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE SIP LEVEL) INSTALLED ON A PULVERIZED COAL BOILER - 58.6 MW (200 × 10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	141,560 (3.5% S)	Stack	-
	303,840 (0.9% S)	Piping	-
	361,400 (0.6% S)	Insulation	
		Painting	-
		Electrical	-
		Subtotal	106,170 (3.5% S)
			227,880 (0.9% S)
			271,050 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	247,730	531,720	632,450
INSTALLATION COSTS, INDIRECT			
Engineering	24,773	53,172	63,245
Construction and field expense	24,773	53,172	63,245
Construction fees	24,773	53,172	63,245
Startup	4,955	10,634	12,649
Performance test	5,000	5,000	5,000
Subtotal	84,274	175,150	207,384
Contingencies	66,400	141,374	167,967
TOTAL TURNKEY COSTS	398,404	848,244	1,007,800
Land	230	230	230
Working Capital	36,604	21,587	24,891
GRAND TOTAL	435,238	870,061	1,032,921
$/m^3/hr	3.43	7.25	8.30
($/acfm)	(5.82)	(12.32)	(14.11)

TABLE 51b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE SIP LEVEL) INSTALLED ON A PULVERIZED COAL BOILER - 58.6 MW (200 × 10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		2,831	6,077	7,228
Electricity		2,495	6,021	7,567
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		138,360	71,520	82,040
Chemicals				
TOTAL DIRECT COSTS		146,415	86,347	99,564
OVERHEAD				
Payroll	819			
Plant		736	1,580	1,879
TOTAL OVERHEAD		1,555	2,399	2,698
CAPITAL CHARGES				
G&A, taxes and insurance		15,936	33,930	40,312
Capital recovery factor		46,812	99,669	118,417
TOTAL CAPITAL CHARGES		62,748	133,599	158,729
TOTAL ANNUALIZED COSTS		210,718	222,345	260,991
$/$10^3$ kg removed		67.01	136.79	139.98
($/ton removed)		(60.92)	(124.35)	(127.25)

TABLE 52a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE SIP LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	114,296 (3.5% S)	Stack	-
	247,344 (0.9% S)	Piping	-
	310,057 (0.6% S)	Insulation	-
		Painting	-
		Electrical	-
		Subtotal	85,722 (3.5% S)
			185,508 (0.9% S)
			232,543 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	200,018	432,852	542,600
INSTALLATION COSTS, INDIRECT			
Engineering	20,002	43,285	54,260
Construction and field expense	20,002	43,285	54,260
Construction fees	20,002	43,285	54,260
Startup	4,000	8,657	10,852
Performance test	5,000	5,000	5,000
Subtotal	69,006	143,512	178,632
Contingencies	53,805	115,273	144,246
TOTAL TURNKEY COSTS	322,829	691,637	865,478
Land	172	172	172
Working Capital	22,426	13,556	15,771
GRAND TOTAL	345,427	705,365	881,421
$/m³/hr	3.14	6.83	8.26
($/acfm)	(5.33)	(11.60)	(14.04)

TABLE 52b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE SIP LEVEL) INSTALLED ON A SPREADER STOKER BOILER - 44 MW (150 × 10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		2,286	4,947	6,201
Electricity		2,048	4,787	5,953
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		82,640	41,760	48,200
Chemicals				
TOTAL DIRECT COSTS		89,703	54,223	63,083
OVERHEAD				
Payroll	819			
Plant		594	1,286	1,612
TOTAL OVERHEAD		1,413	2,105	2,431
CAPITAL CHARGES				
G&A, taxes and insurance		12,913	27,665	34,619
Capital recovery factor		37,932	81,267	101,694
TOTAL CAPITAL CHARGES		50,845	108,932	136,313
TOTAL ANNUALIZED COSTS		141,961	165,260	201,827
$/$10^3$ kg removed		75.58	174.13	184.24
($/ton removed)		(68.71)	(158.30)	(167.49)

TABLE 53a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE SIP LEVEL) INSTALLED ON A CHAIN GRATE STOKER BOILER - 22 MW (75×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	34,143 (3.5% S)	Stack	-
	63,200 (0.9% S)	Piping	-
	91,514 (0.6% S)	Insulation	-
		Painting	-
		Electrical	-
		Subtotal	25,607 (3.5% S)
			47,400 (0.9% S)
			68,636 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	59,750	110,600	160,150
INSTALLATION COSTS, INDIRECT			
Engineering	5,975	11,060	16,015
Construction and field expense	5,975	11,060	16,015
Construction fees	5,975	11,060	16,015
Startup	1,195	2,212	3,203
Performance test	5,000	5,000	5,000
Subtotal	24,120	40,392	56,248
Contingencies	16,774	30,198	43,280
TOTAL TURNKEY COSTS	100,644	181,190	259,678
Land	86	86	86
Working Capital	4,296	2,621	3,160
GRAND TOTAL	105,026	183,897	262,924
$/m³/hr	1.91	3.60	4.93
($/acfm)	(3.25)	(6.11)	(8.37)

TABLE 53b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE SIP LEVEL) INSTALLED ON A CHAIN GRATE STOKER BOILER - 22 MW (75×10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		683	1,264	1,830
Electricity		773	1,370	1,722
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		13,000	5,120	6,360
Chemicals				
TOTAL DIRECT COSTS		17,185	10,483	12,641
OVERHEAD				
Payroll	819			
Plant		178	329	476
TOTAL OVERHEAD		997	1,148	1,295
CAPITAL CHARGES				
G&A, taxes and insurance		4,026	7,248	10,387
Capital recovery factor		11,826	21,290	30,512
TOTAL CAPITAL CHARGES		15,852	28,538	40,899
TOTAL ANNUALIZED COSTS		34,034	40,169	54,835
$\$/10^3$ kg removed		115.19	345.20	379.36
(\$/ton removed)		(104.72)	(313.82)	(344.87)

TABLE 54a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE SIP LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER - 8.8 MW (30×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	13,257 (3.5% S)	Stack	-
	25,629 (0.9% S)	Piping	-
	35,886 (0.6% S)	Insulation	-
		Painting	-
		Electrical	-
		Subtotal	9,943 (3.5% S)
			19,221 (0.9% S)
			26,914 (0.6% S)

	3.5% S	0.9% S	0.6% S
TOTAL DIRECT COSTS (equipment and installation)	23,200	44,850	62,800
INSTALLATION COSTS, INDIRECT			
Engineering	2,320	4,485	6,280
Construction and field expense	2,320	4,485	6,280
Construction fees	2,320	4,485	6,280
Startup	464	897	1,256
Performance test	5,000	5,000	5,000
Subtotal	12,424	19,352	25,096
Contingencies	7,125	12,840	17,579
TOTAL TURNKEY COSTS	42,749	77,042	105,475
Land	34	34	34
Working Capital	2,123	1,456	1,661
GRAND TOTAL	44,906	78,532	107,170
$\$/m^3/hr$	2.05	3.79	5.04
(\$/acfm)	(3.48)	(6.44)	(8.57)

TABLE 54b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE SIP LEVEL) INSTALLED ON AN UNDERFEED STOKER BOILER - 8.8 MW (30×10^6 Btu/hr) INPUT

		3.5 percent S	0.9 percent S	0.6 percent S
DIRECT COSTS				
Direct labor	2,211			
Supervision	518			
Maintenance labor, materials and parts		265	513	718
Electricity		298	542	678
Steam				
Cooling water				
Process water				
Fuel				
Waste disposal		5,200	2,040	2,520
Chemicals				
TOTAL DIRECT COSTS		8,492	5,824	6,645
OVERHEAD				
Payroll	819			
Plant		69	133	187
TOTAL OVERHEAD		888	952	1,006
CAPITAL CHARGES				
G&A, taxes and insurance		1,710	3,082	4,219
Capital recovery factor		5,023	9,052	12,393
TOTAL CAPITAL CHARGES		6,733	12,134	16,612
TOTAL ANNUALIZED COSTS		16,113	18,910	24,263
$/$10^3$ kg removed		136.35	407.86	423.64
($/ton removed)		(123.95)	(370.78)	(385.13)

To determine the economic impact of each of the 60 cost estimates, Table 55 is presented to show the percentage increase in annualized costs over uncontrolled boilers and, where possible, SIP-controlled boilers. Each of the examples in Table 55 corresponds to part b of Tables 33 through 54. The cost differences are shown to be very significant and represent increases from about 3.5 to 14.7 percent over uncontrolled boilers and 0.9 to 5.5 percent over SIP-controlled units.

TABLE 55. COSTS OF "BEST" PARTICULATE CONTROL TECHNIQUES FOR COAL-FIRED BOILERS

	System				Annualized costs ($)	Annualized costs $/J/sec ($/10^6 Btu/hr)	Impact based upon annualized cost	
	Standard boilers		Type/and level of control	Control efficiency (%)			% Increase in* costs over the uncontrolled boiler	% Increase in† costs over the SIP-controlled boiler
	Heat input MW (10^6 Btu/hr)	Type						
1.	58.6 (200) 0.6-3.5% S	Pulverized coal	Fabric filter/ Stringent	99+	~263,000 to 330,000	0.0045 - 0.0056 (1315 - 1650)	~6.0 - 7.8%	NA
2.	58.6 (200) 0.6-3.5% S	Pulverized coal	ESP/ intermediate	99+	~263,000 to 303,000	0.0045 - 0.005 (1315 - 1515)	~6.2 - 7.0%	~0.9 - 1.2%
3.	58.6 (200) 0.6-3.5% S	Pulverized coal	ESP/ stringent	99.25 to 99.58	~279,000 to 322,000	0.0048 - 0.0055 (1395 - 1610)	~6.6 - 7.4%	~1.3 - 1.5%
4.	44 (150) 0.6-3.5% S	Spreader stoker	ESP and MC in series/ intermediate	99+	~212,000 to 282,000	0.0048 - 0.0064 (1413 - 1880)	~6.9 - 9.0%	NA
5.	44 (150) 0.6-3.5% S	Spreader stoker	Fabric filter/ Stringent	99+	~198,000 to 239,000	0.0045 - 0.0054 (1320 - 1593)	~6.2 - 7.8%	NA
6.	44 (150) 0.6-3.5% S	Spreader stoker	Wet scrubber/ intermediate	99+	~250,000	0.0057 (1667)	~8.1%	NA
7.	45 (154) 0.8 % S	Spreader stoker	ESP/ intermediate	97.3	~212,000	0.0047 (1377)	~6.6%	NA
8.	55 (188) 0.8% S	Spreader stoker	Fabric filter/ stringent	99.7	~244,000	0.0044 (1298)	~6.1%	NA
9.	44 (150) 0.6-3.5% S	Spreader stoker	ESP/ stringent	99.1 to 99.5	~205,000 to 265,000	0.0047 - 0.006 (1367 - 1767)	~6.7 - 8.5%	~2.0%
10.	40 (137) 0.8% S	Chain grate stoker	MC/ moderate	97.0	~195,000	0.0049 (1423)	~7.8%	NA
11.	22 (75) 0.6-3.5% S	Chain grate stoker	Wet scrubber/ stringent	~98	~280,000	0.013 (3733)	~14.7%	NA

(continued)

TABLE 55 (continued)

	System				Annualized costs ($)	Annualized costs $/J/sec ($/10^6 Btu/hr)	Impact based upon annualized cost	
	Standard boilers		Type/and level of control	Control efficiency (%)			% Increase in* costs over the uncontrolled boiler	% Increase in† costs over the SIP-controlled boiler
	Heat input MW (10^6 Btu/hr)	Type						
12.	22 (75) 0.6-3.5% S	Chain grate stoker	Wet scrubber/ intermediate	92.0 to 95.56	~150,000	0.0068 (2000)	~7.9%	NA
13.	22 (75) 0.6-3.5% S	Chain grate stoker	ESP/ stringent	97.60 to 98.67	~73,000 to 157,000	0.0033 - 0.007 (973 - 2093)	~3.9 - 8.4%	~2.1 - 5.3%
14.	8.8 (30) 0.6-3.5% S	Underfeed stoker	ESP and MC in series/ intermediate	99+	~37,000 to 67,000	0.0042 - 0.0076 (1233 - 2233)	~3.9 - 6.9%	NA
15.	8.8 (30) 0.6-3.5% S	Underfeed stoker	Fabric filter/ Stringent	99+	~56,000	0.0064 (1867)	~5.8%	NA
16.	8.8 (30) 0.6-3.5% S	Underfeed stoker	ESP/ stringent	97.60 to 98.66	~33,000 to 79,000	0.0038 - 0.009 (1100 - 2633)	~3.5 - 8.1%	~1.8 - 5.5%
17.	58.6 (200) 0.6-3.5% S	Pulverized coal	ESP/SIP	85.00 to 91.64	211,000 to 261,000	0.0036 - 0.0045 (1055 - 1305)	~5.0 - 6.0%	-
18.	44 (150) 0.6-3.5% S	Spreader stoker	ESP/SIP	81.54 to 89.73	142,000 to 202,000	0.0032 - 0.0046 (947 - 1347)	~4.6 - 6.5%	-
19.	22 (75) 0.6-3.5% S	Chain grate stoker	ESP/SIP	52.00 to 73.33	34,000 to 55,000	0.0015 - 0.0025 (453 - 733)	~1.8 - 2.9%	-
20.	8.8 (30) 0.6-3.5% S	Underfeed stoker	ESP/SIP	52.00 to 73.21	16,000 to 24,000	0.0018 - 0.0027 (533 - 800)	~1.7 - 2.5%	-

$$^{*}\ \frac{\text{Annualized cost}}{\text{Annualized uncontrolled boiler cost}} \times 100$$

$$^{\dagger}\ \frac{\text{Annualized cost - SIP Annualized cost}}{\text{Annualized uncontrolled boiler cost + SIP Annualized cost}} \times 100$$

Note: NA = Not Available

4.2 COSTS TO CONTROL OIL-FIRED BOILERS

Electrostatic precipitators were cited in Sections 2.0 and 3.0 as being the best and possibly the only control device that could be used on residual oil-fired boilers. (Controls were shown to be unnecessary in the case of distillate oil for properly operated steam plants.) Required control efficiencies for residual oil-fired units were shown in Section 3.0 to range up to 92 percent depending upon the level of emission reduction. The only equipment manufacturer who quoted a price for an ESP (Vendor A)[22] quoted an efficiency of 75 percent as indicative of the intermediate level of emission reduction. The capital cost for equipment and installation was given as $325,000 and $193,000, respectively. The detailed cost estimate shown in Table 56 indicates that control at this level is not very cost effective due to the relatively low inlet dust loading. Electircal consumption for this case is about $3,282 per year based on 26.4 kW (see Table 62) and 4,818 hours of operation per year (0.55 load factor). The cost impact is shown in Table 57.

4.3 COSTS TO CONTROL GAS-FIRED BOILERS

In Section 2.0 it was noted that particulate controls would be unnecessary for properly operated gas-fired boilers and therefore no cost analyses have been performed for these types of units.

TABLE 56a. CAPITAL COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A RESIDUAL OIL-FIRED BOILER - 44 MW (150×10^6 Btu/hr) INPUT

EQUIPMENT COSTS		INSTALLATION COSTS, DIRECT	
Basic equipment (includes freight)	-	Foundations and supports	-
Required auxiliaries	-	Ductwork	-
Subtotal	325,000	Stack	-
		Piping	-
		Insulation	-
		Painting	-
		Electrical	-
		Subtotal	193,000

	3.0% S
TOTAL DIRECT COSTS (equipment and installation)	518,000
INSTALLATION COSTS, INDIRECT	
Engineering	51,800
Construction and field expense	51,800
Construction fees	51,800
Startup	10,360
Performance test	5,000
Subtotal	170,760
Contingencies	137,752
TOTAL TURNKEY COSTS	826,512
Land	172
Working Capital	3,504
GRAND TOTAL	830,188
$\$/m^3/hr$	10.46
($/acfm)	(17.77)

TABLE 56b. ANNUALIZED COSTS FOR AN ELECTROSTATIC PRECIPITATOR (AT THE INTERMEDIATE LEVEL) INSTALLED ON A RESIDUAL OIL-FIRED BOILER - 44 MW (150 × 10^6 Btu/hr) INPUT

	3.0 percent S
DIRECT COSTS	
Direct labor	2,027
Supervision	474
Maintenance labor, materials and parts	6,500
Electricity	3,282
Steam	
Cooling water	
Process water	
Fuel	
Waste disposal	1,733
Chemicals	
TOTAL DIRECT COSTS	14,016
OVERHEAD	
Payroll	750
Plant	1,690
TOTAL OVERHEAD	2,440
CAPITAL CHARGES	
G&A, taxes and insurance	33,060
Capital recovery factor	97,115
TOTAL CAPITAL CHARGES	130,175
TOTAL ANNUALIZED COSTS	146,631
$/$10^3$ kg removed	3,751
($/ton removed)	(3,410)

TABLE 57. COSTS OF "BEST" PARTICULATE CONTROL TECHNIQUE FOR A RESIDUAL OIL-FIRED BOILER

System				Annualized costs ($)	Annualized costs $/J/sec ($/10^6 Btu/hr)	Impact based upon annualized cost	
Standard boiler		Type/and level of control	Control efficiency (%)			% Increase in costs over the uncontrolled boiler*	% Increase in costs over the SIP-controlled boiler
Heat input MW (10^6 Btu/hr)	Type						
44 (150) 3.0% S	Residual oil	ESP/ intermediate and SIP	75	~146,600	0.0033 (978)	~4.5 %	-

$$^{*}\ \frac{\text{Annualized cost}}{\text{Annualized uncontrolled boiler cost}} \times 100$$

4.4 SUMMARY

The cost ranges for the purchase, installation, operation and maintenance of particulate control equipment are summarized in this section. Where possible, all cost data have been adjusted to June 1978 dollars. All costs related to labor and electricity or other energy costs, as well as percentages assigned to the annualization of capital costs, have been provided by PEDCo.

The cost estimates have revealed several important trends in control equipment costs with respect to coal sulfur content and emission control level. First of all, the fabric filter is shown to be more cost-effective (annualized cost divided by weight of pollutant removed per year) than the electrostatic precipitator at the stringent level when the 0.9 and 0.6 percent sulfur coals are burned. (This conclusion is supported by independent data presented in Figure 26.) When 3.5 percent sulfur coal is burned, the ESP becomes more cost-effective except on the smallest (8.8 MW input) of the standard boilers (the underfeed stoker boiler).

With respect to emission control levels, the ESP annualized costs are shown to increase significantly when the control levels become more stringent as shown in Figures 33 through 36 for the four coal-fired boilers. (The difference in scale for the annualized cost for the chain grate and underfeed stoker units should be noted.)

The costs presented for particulate emission control are subject to various inaccuracies resulting from vendor quotes, capitalization and annualization estimating techniques, and various other assumptions and computations. Budgetary prices quoted by vendors are typically ± 10 percent. For fabric filters and mechanical collectors, therefore, the costs are accurate to this figure. For precipitators and scrubbers, however, the costs are accurate to ± 20 percent, due to additional calculations and assumptions.

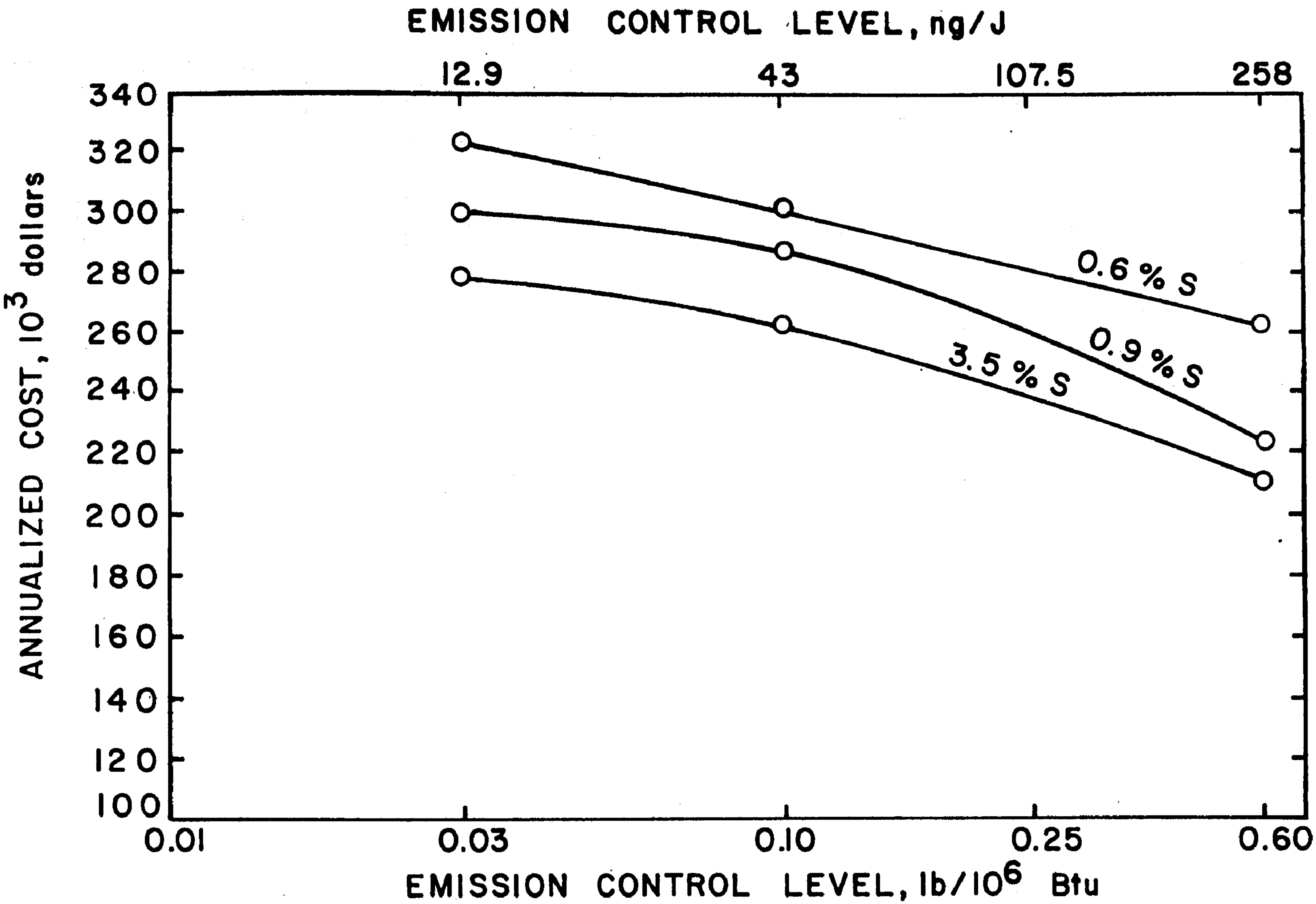

Figure 33. Annualized cost of an ESP installed on a pulverized coal boiler (58.6 MW or 200 x 10^6 Btu/hr heat input) as a function of emission control level and coal sulfur content.

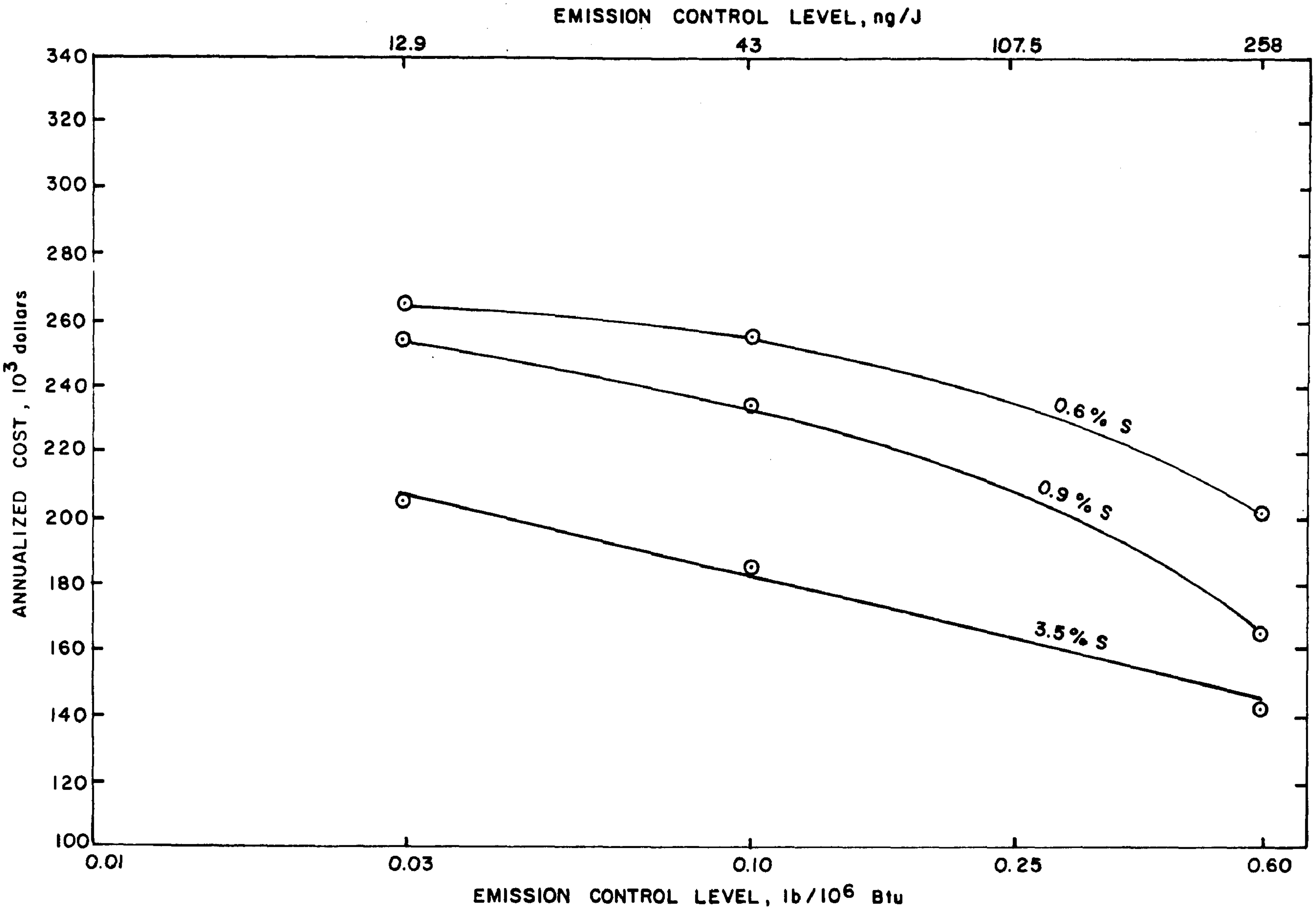

Figure 34. Annualized cost of an ESP installed on a spreader stoker boiler (44 MW or 150 × 10^6 Btu/hr heat input) as a function of emission control level and coal sulfur content.

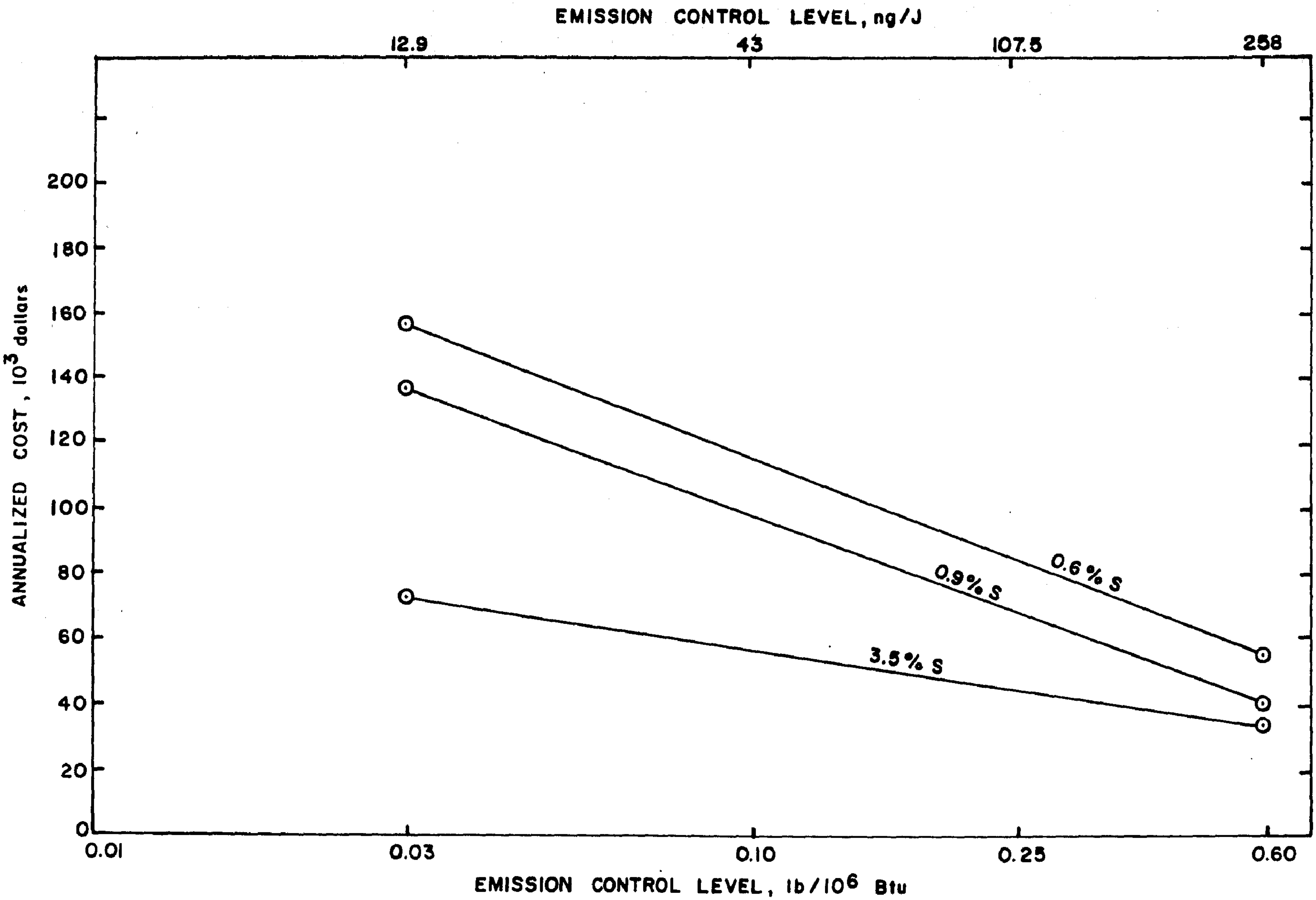

Figure 35. Annualized cost of an ESP installed on a chain grate stoker boiler (22 MW or 75 × 10^6 Btu/hr heat input) as a function of emission control level and coal sulfur content.

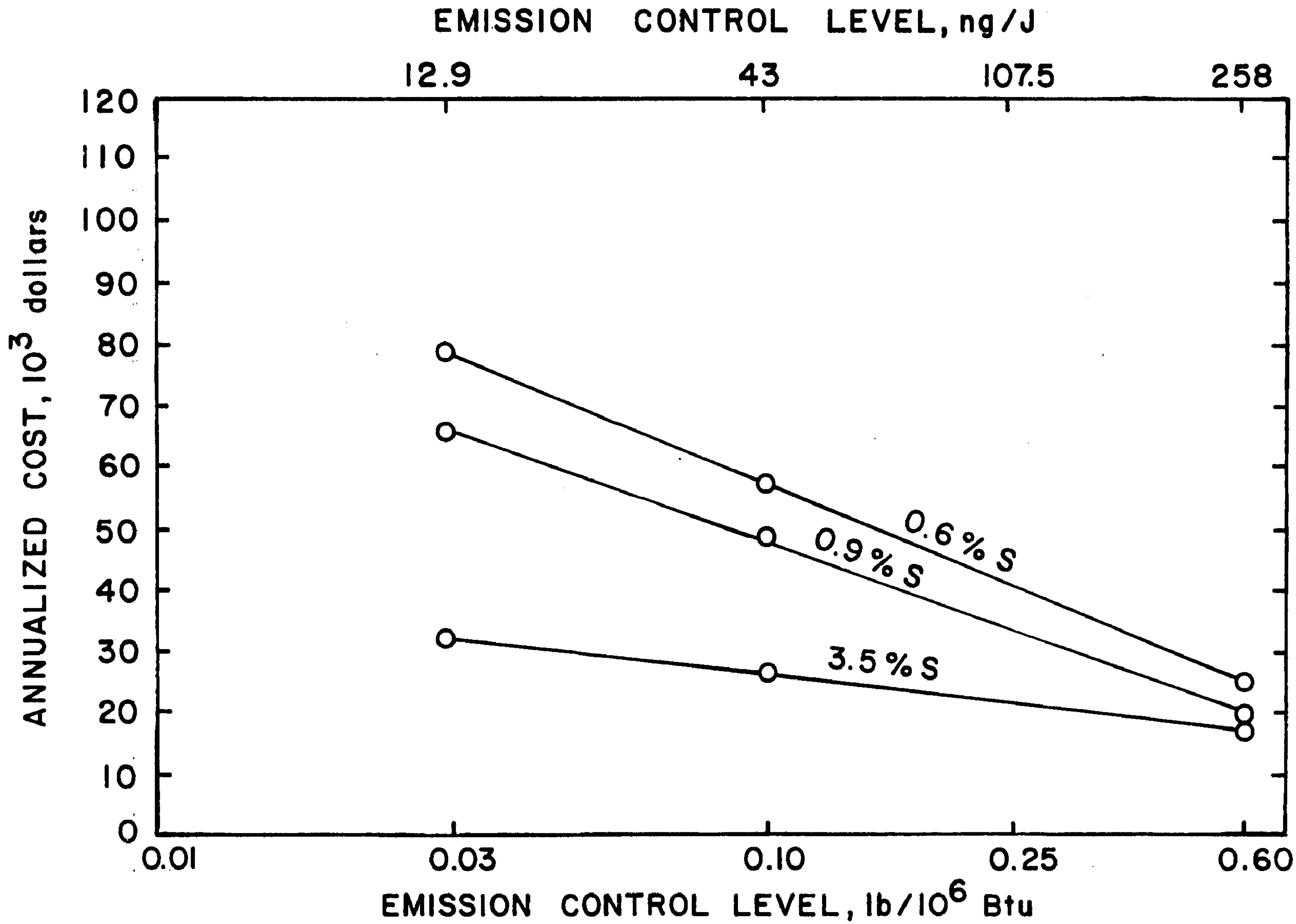

Figure 36. Annualized cost of an ESP installed on an underfeed stoker boiler (8.8 MW or 30 x 10^6 Btu/hr heat input) as a function of emission control level and coal sulfur content.

4.5 REFERENCES

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5.0 ENERGY IMPACT OF CANDIDATES FOR BEST EMISSION CONTROL SYSTEMS

5.1 INTRODUCTION

The primary energy impact arising from the installation of particulate control equipment is the consumption of electrical power to operate the control device(s). All systems require a fan sized to overcome the pressure losses generated by the duct, breechings, stack and, in particular, the fly ash collector itself. In the case of an electrostatic precipitator (ESP), additional energy is required to create the corona discharge and to run auxiliary equipment such as electrode rappers and the ash conveying system.

For fabric filtration (FF) systems, energy is also required to operate the cleaning equipment (a reverse air fan, a compressor for pulse systems or a mechanical shaker) as well as the ash conveying system. A wet scrubber (WS) requires a liquid pump/slurry handling system and a mechanical collector (MC) requires an ash removal system over and above the standard gas moving fans.

5.2 ENERGY IMPACT OF CONTROLS FOR COAL-FIRED BOILERS

5.2.1 New Facilities

Energy consumption for the various candidate control systems is indicated in this section. Fan and pump power requirements, Table 58, show the energy usage for all control systems that might conceivably achieve the required efficiency level given previously in Table 31. Pump requirements are calculated for scrubber systems only. Various pressure drops are assumed for wet scrubbers depending upon uncontrolled fly ash loadings and size properties.

TABLE 58. FAN AND PUMP POWER REQUIREMENTS OF PARTICULATE CONTROLS FOR COAL-FIRED BOILERS

Boiler type, heat input and fuel	Flow rate* Q (acfm)	Δ P† inches W.C.	Control device	Energy requirements‡			
				Fan		Pump	
				hp	kW	hp	kW
A. Pulverized coal 58.6 MW (200×10^6 Btu/hr)							
3.5% S	74,800	0.5	Cold ESP	10.6	7.9	-	-
3.5% S	74,800	6.0	FF	128	95.4	-	-
0.9% S	105,500	0.5	Hot ESP	15	11.2	-	-
0.9% S	70,600	6.0	FF	121	90.2	-	-
0.6% S	109,800	0.5	Hot ESP	15.6	11.6	-	-
0.6% S	73,200	6.0	FF	125	93.2	-	-
0.6% S	73,200	15.0	WS	351	262	36.6	27.3
0.6% S	73,200	20.0	WS	417	311	36.6	27.3
B. Spreader stoker 44.0 MW (150×10^6 Btu/hr)							
3.5% S	64,800	0.5	Cold ESP	9.2	6.9	-	-
3.5% S	64,800	6.0	FF	110.8	82.6	-	-
3.5% S	64,800	5.0	WS	92.3	68.8	32.4	24.2
3.5% S	64,800	10.0	WS	185	138	32.4	24.2
3.5% S	64,800	15.0	WS	277	207	32.4	24.2
0.9% S	91,200	0.5	Hot ESP	13	9.7	-	-
0.9% S	60,800	6.0	FF	104	77.6	-	-
0.9% S	60,800	5.0	WS	86.6	64.6	30.4	22.7
0.9% S	60,800	10.0	WS	173	129	30.4	22.7
0.6% S	94,200	0.5	Hot ESP	13.4	10.0	-	-
0.6% S	62,800	6.0	FF	107.4	80.1	-	-
0.6% S	62,800	5.0	WS	89.5	66.7	31.4	23.4
0.6% S	62,800	10.0	WS	179	133.5	31.4	23.4
0.6% S	62,800	15.0	WS	269	200.6	31.4	23.4
C. Chain grate stoker 22.0 MW (75×10^6 Btu/hr)							
3.5% S	32,300	0.5	Cold ESP	4.6	3.4	-	-
3.5% S	32,300	6.0	FF	55.2	41.2	-	-
3.5% S	32,300	5.0	WS	46	34.3	16.2	12.1
3.5% S	32,300	10.0	WS	92	68.6	16.2	12.1
3.5% S	32,300	15.0	WS	138	102.9	16.2	12.1

(continued)

TABLE 58 (continued)

Boiler type, heat input and fuel	Flow rate* Q (acfm)	Δ P† inches W.C.	Control device	Energy requirements‡			
				Fan		Pump	
				hp	kW	hp	kW
Chain grate stoker (continued)							
0.9% S	45,150	0.5	Hot ESP	6.4	4.8	-	-
0.9% S	30,100	6.0	FF	51.5	38.4	-	-
0.9% S	30,100	5.0	WS	43	32	15	11.2
0.9% S	30,100	10.0	WS	86	64	15	11.2
0.9% S	30,100	15.0	WS	129	96	15	11.2
0.9% S	30,100	4.0	MC	34.3	25.6	-	-
0.6% S	47,100	0.5	Hot ESP	6.7	5.0	-	-
0.6% S	31,400	6.0	FF	53.7	40.0	-	-
0.6% S	31,400	5.0	WS	45	33.5	15.7	11.7
0.6% S	31,400	10.0	WS	89.5	66.7	15.7	11.7
0.6% S	31,400	15.0	WS	134.2	100.1	15.7	11.7
0.6% S	31,400	4.0	MC	35.8	26.7	-	-
D. Underfeed stoker 8.8 MW (30×10^6 Btu/hr)							
3.5% S	12,900	0.5	Cold ESP	1.8	1.3	-	-
3.5% S	12,900	6.0	FF	22	16.4	-	-
3.5% S	12,900	20.0	WS	73.5	54.8	6.45	4.8
0.9% S	18,300	0.5	Hot ESP	2.6	1.9	-	-
0.9% S	12,200	6.0	FF	20.9	15.6	-	-
0.9% S	12,200	10.0	WS	34.8	26	6.1	4.5
0.9% S	12,200	15.0	WS	52.2	38.9	6.1	4.5
0.6% S	18,750	0.5	Hot ESP	2.7	2.0	-	-
0.6% S	12,500	6.0	FF	21.4	16.0	-	-
0.6% S	12,500	5.0	WS	17.8	13.3	6.3	4.7
0.6% S	12,500	10.0	WS	35.6	26.6	6.3	4.7
0.6% S	12,500	15.0	WS	53.4	39.8	6.3	4.7
0.6% S	12,500	4.0	MC	14.3	10.7	-	-

(continued)

TABLE 58 (continued)

Boiler type, heat input and fuel	Flow rate* Q (acfm)	Δ P† inches W.C.	Control device	Energy requirements‡			
				Fan		Pump	
				hp	kW	hp	kW
E. Pulverized coal 117.2 MW (400×10^6 Btu/hr)							
3.5% S	149,639	0.5	Cold ESP	21.3	15.9	-	-
3.5% S	149,639	6.0	FF	256	191	-	-
2.3% S	151,153	0.5	Cold ESP	21.5	16	-	-
2.3% S	151,153	6.0	FF	258	192	-	-
0.9% S	211,418	0.5	Hot ESP	30.1	22.4	-	-
0.9% S	141,528	6.0	FF	242	180	-	-
0.6% S	218,024	0.5	Hot ESP	31.1	23.2	-	-
0.6% S	145,950	6.0	FF	250	186	-	-
0.6% S	145,950	15.0	WS	624	465	73	54.4
0.6% S	145,950	20.0	WS	832	620	73	54.4

*To convert acfm to m^3/hr, multiply by 1.699

†To convert inches W.C. to kPa, multiply by 0.2488

‡Any energy requirements supplied by the boiler would have to be multiplied by ~3.0 because of boiler/turbine efficiency.

The fan power requirements are estimated from the following equation:[1]

$$P = 2.85 \times 10^{-4} Q_I \Delta P \tag{1}$$

where P = power consumed, hp

Q_I = gas flow, acfm

ΔP = pressure drop, inches water column

This equation is based on an assumed combined efficiency of 55 percent for fan and motor.

The liquid pump requirements for a scrubber system are based upon a power parameter of 17.6 hp/1000 m^3/min (0.5 hp/1000 acfm).[2] The flow rate, pressure drop, and collector type are given in Table 58 for each of the coal-fired boiler systems. A cold electrostatic precipitator has been selected for the 3.5 and 2.3 percent sulfur coals. In the case of low-sulfur coals (0.9 percent and 0.6 percent) hot-side precipitation was selected such that the gas flow volumes were appreciably increased. It is realized that this type of approach is rather simplified and certainly some vendors would specify cold-side ESPs for any coal type. However, the lack of a detailed coal analysis has prevented any other type of design consideration.

Table 59 lists the various design parameters for electrostatic precipitators that relate to the coal-fired boiler systems of interest. For the current analysis, two basic equations were used:[3]

$$W_k = W \ln\left(\frac{1}{Q}\right) \tag{2}$$

and

$$\frac{A}{V} = \frac{1}{W_k} \ln^2\left(\frac{1}{Q}\right) \tag{3}$$

where A = plate area

V = gas flow

Q = fractional penetration

W_k = modified precipitation rate parameter

W = migration velocity or precipitation rate

TABLE 59. DESIGN PARAMETERS AND ENERGY CONSUMPTION OF ELECTROSTATIC PRECIPITATORS ON COAL-FIRED BOILERS

Boiler type, heat input and fuel	Type and level of control	Control efficiency (percent)	Precipitation rate, W_k * (fpm)	SCA† ($ft^2/10^3$ acfm)	Plate‡ area (ft^2)	Power consumption§	
						To energize Corona (kW)	Auxiliary (kW)
Pulverized coal 58.6 MW (200×10^6 Btu/hr)							
3.5% S	Cold ESP						
	SIP	91.64	89	69	5,161	7.7	2.8
	Moderate	96.52	121	93	6,956	10.4	3.9
	Intermediate	98.61	154	119	8,901	13.4	5.1
	Stringent	99.58	197	152	11,370	17.1	6.7
0.9% S	Hot ESP						
	SIP	85.00	28	126	13,293	25.3	7.9
	Moderate	93.75	42	185	19,518	37.1	12.2
	Intermediate	97.50	55	246	25,953	49.3	16.7
	Stringent	99.25	73	326	34,393	65.3	22.8
0.6% S	Hot ESP						
	SIP	86.67	25	160	17,568	33.4	10.8
	Moderate	94.44	36	229	25,144	47.8	16.1
	Intermediate	97.78	48	302	33,160	63.0	21.9
	Stringent	99.33	63	397	43,591	82.8	29.6
Spreader stoker 44.0 MW (150×10^6 Btu/hr)							
3.5% S	Cold ESP						
	SIP	89.73	82	63	4,082	6.1	2.1
	Moderate	95.72	113	88	5,702	8.6	3.1
	Intermediate	98.29	146	113	7,322	11.0	4.1
	Stringent	99.49	190	147	9,526	14.3	5.5
0.9% S	Hot ESP						
	SIP	81.54	25	113	10,306	19.6	6.0
	Moderate	92.31	38	171	15,595	29.6	9.5
	Intermediate	96.92	52	232	21,158	40.2	13.3
	Stringent	99.08	70	313	28,546	54.2	18.5
0.6% S	Hot ESP						
	SIP	83.61	23	144	13,565	25.8	8.1
	Moderate	93.17	34	213	20,065	38.1	12.5
	Intermediate	97.27	45	286	26,941	51.2	17.4
	Stringent	99.18	61	381	35,890	68.2	23.9

(continued)

TABLE 59 (continued)

Boiler type, heat input and fuel	Type and level of control	Control efficiency (percent)	Precipitation rate, W_k * (fpm)	SCA† ($ft^2/10^3$ acfm)	Plate‡ area (ft^2)	Power consumption§	
						To energize Corona (kW)	Auxiliary (kW)
Chain grate stoker 22.0 MW (75×10^6 Btu/hr)							
3.5% S	Cold ESP						
	SIP	73.33	48	37	1,195	1.8	0.5
	Moderate	88.89	79	61	1,970	3.0	0.9
	Intermediate	95.56	112	87	2.810	4.2	1.4
	Stringent	98.67	156	120	3,876	5.8	2.0
0.9% S	Hot ESP						
	SIP	52.00	11	49	2,212	4.2	1.1
	Moderate	80.00	24	107	4,831	9.2	2.6
	Intermediate	92.00	38	168	7,585	14.4	4.3
	Stringent	97.60	56	249	11,242	21.4	6.6
0.6% S	Hot ESP						
	SIP	57.45	11	68	3,203	6.1	1.6
	Moderate	82.27	22	137	6,453	12.3	3.6
	Intermediate	92.91	33	210	9,891	18.8	5.7
	Stringent	97.87	48	305	14,366	27.3	8.6
Underfeed stoker 8.8 MW (30×10^6 Btu/hr)							
3.5% S	Cold ESP						
	SIP	73.21	47	36	464	0.7	0.2
	Moderate	88.84	79	61	787	1.2	0.3
	Intermediate	95.54	112	86	1,109	1.7	0.5
	Stringent	98.66	155	120	1,548	2.3	0.7
0.9% S	Hot ESP						
	SIP	52.00	11	49	897	1.7	0.4
	Moderate	80.00	24	107	1,958	3.7	0.9
	Intermediate	92.00	38	168	3,074	5.8	1.6
	Stringent	97.60	56	249	4,557	8.7	2.4
0.6% S	Hot ESP						
	SIP	57.14	11	67	1,256	2.4	0.6
	Moderate	82.14	22	137	2,569	4.9	1.3
	Intermediate	92.86	33	209	3,919	7.4	2.0
	Stringent	97.86	48	305	5,719	10.9	3.1

*To convert from fpm to cm/sec, multiply by 0.508

†To convert from $ft^2/10^3$ acfm to m^2/acm/min, multiply by 3.28

‡To convert ft^2 to m^2, multiply by 0.0929

§Any energy requirements supplied by the boiler would have to be multiplied by ~3.0 because of boiler/turbine efficiency.

TABLE 59 (continued)

Boiler type, heat input and fuel	Type and level of control	Control efficiency (percent)	Precipitation rate, W_k (fpm)	SCA† ($ft^2/10^3$ acfm)	Plate‡ area (ft^2)	Power consumption: To energize Corona (kW)	Power consumption: Auxiliary (kW)
Pulverized coal 117.2 MW (400×10^6 Btu/hr)							
3.5% S	Cold ESP						
	SIP	91.64	89	69	10,325	15.5	6.0
	Moderate	96.52	121	93	13,916	20.9	8.3
	Intermediate	98.61	154	119	17,807	26.7	11.0
	Stringent	99.58	197	152	22,745	34.1	14.4
2.3% S	Cold ESP						
	SIP	92.49	62	108	16,325	24.5	10.0
	Moderate	96.87	83	145	21,917	32.9	13.8
	Intermediate	98.75	105	183	27,661	41.5	17.9
	Stringent	99.62	134	232	35,067	52.6	23.3
0.9% S	Hot ESP						
	SIP	85.00	28	126	26,639	50.6	17.2
	Moderate	93.75	42	185	39,112	74.3	26.3
	Intermediate	97.50	55	246	52,009	98.8	36.1
	Stringent	99.25	73	326	68,922	131.0	49.3
0.6% S	Hot ESP						
	SIP	86.67	25	160	34,884	66.3	23.1
	Moderate	94.44	36	229	49,927	94.9	34.5
	Intermediate	97.78	48	302	65,843	125.1	46.9
	Stringent	99.33	63	397	86,556	164.5	63.5

*To convert from fpm to cm/sec, multiply by 0.508

†To convert from $ft^2/10^3$ acfm to m^2/acm/min, multiply by 3.28

‡To convert ft^2 to m^2, multiply by 0.0929

§Any energy requirements supplied by the boiler would have to be multiplied by ~3.0 because of boiler/turbine efficiency.

Values of W were obtained from the Electrostatic Precipitator Manual,[4] in which W values are specified as a function of coal sulfur content as shown below:

$W \cong 18.3$ cm/sec (0.6 ft/sec) at 3.5% S
$W \cong 12.2$ cm/sec (0.4 ft/sec) at 2.3% S
$W \cong 7.6$ cm/sec (0.25 ft/sec) at 0.9% S
$W \cong 6.4$ cm/sec (0.21 ft/sec) at 0.6% S

Using these velocities, W_k is calculated followed by the computation of plate area based upon the desired fractional penetration. The efficiency values are obtained from Table 31 and, in the case of the SIP (State Implementation Plan) control level, the efficiency is calculated using the average uncontrolled emission level for the given boiler and the average SIP requirement of 258 ng/J (0.6 lb/10^6 Btu) for coal-fired boilers.

Once the appropriate ESP design parameters are established, the power consumption to energize the corona and to operate auxiliary equipment (e.g., electrode rappers and ash handling equipment) is calculated by means of the following two equations:

Energizing Power:[5]

$$P = A\ D \times 10^{-3} \tag{4}$$

where P = power consumption, kW
A = plate area, m^2 (ft^2)
D = input power density:

Cold ESP $\cong 16.15$ watts/m^2 (1.5 watts/ft^2)
Hot ESP $\cong 20.45$ watts/m^2 (1.9 watts/ft^2)

Auxiliary Power:[6]

$$P = 2.1 \times 10^{-4}\ (A)^{1.11} \tag{5}$$

where P = power consumption, kW
A = plate area, m^2 (ft^2)

For particulate control by electrostatic precipitators, the total energy usage is the sum of the fan, corona, and auxiliary power requirements. In the case of scrubbers, total energy consumption is defined by fan and pump requirements only. Energy usage by fabric filters is given as a function of air flow requirements only. Reverse air fan or compressor power requirements for cleaning are not included since many types of systems are available and all vary in their design and operation. The pressure drop utilized for baghouse computations is 1.5 kPa (6.0 inches W.C.) which may be excessive for normally operated baghouse units. It is believed, therefore, that this excess pressure loss will take into account cleaning energy requirements. Multitube cyclone energy consumption is based solely on a 1.0 kPa (4.0 inches W.C.) pressure loss.

The final tabulation of electrical energy consumption is presented in Table 60. Energy consumption is given in kW for each control device at the specified levels of control. These values are then expressed as a percentage of boiler heat input — to give the percent increase in energy consumption over the uncontrolled boiler case — and as a percentage of boiler heat input plus the SIP energy requirement — to give the percent increase in energy consumption over that required at the SIP level of control. (See the footnote at the bottom of Table 60.)

Table 60 shows several important trends in control device energy usage. For example, the increase in electrical requirements for an ESP on a pulverized coal boiler (58.6 MW input) burning 0.6 percent sulfur coal from the SIP level to the stringent level is significant. The required efficiency increases from 86.67 to 99.33 percent (a 15 percent increase), whereas the energy consumed

TABLE 60. ELECTRICAL ENERGY CONSUMPTION FOR PARTICULATE CONTROL TECHNIQUES FOR COAL-FIRED BOILERS

System					Electrical energy consumption		
Standard boiler			Type and level of control	Control efficiency (percent)	Energy consumed by control device (kW)	% Increase in energy use over uncontrolled boiler *	% Change in energy use over SIP controlled boiler †
MW	Heat input (10^6 Btu/hr)	Type					
58.6	(200)	Pulverized coal	**ESP**				
3.5% S			SIP	91.64	18.4	0.031	0
10.6% A			Moderate	96.52	22.2	0.038	+ 0.006
			Intermediate	98.61	26.4	0.044	+ 0.014
			Stringent	99.58	31.7	0.055	+ 0.023
			FF				
			SIP	91.64	95.4	0.164	0
			Moderate	96.52	95.4	0.164	0
			Intermediate	98.61	95.4	0.164	0
			Stringent	99.58	95.4	0.164	0
			ESP				
0.9% S			SIP	85.00	44.4	0.075	0
6.9% A			Moderate	93.75	60.5	0.102	+ 0.027
			Intermediate	97.50	77.2	0.133	+ 0.056
			Stringent	99.25	99.3	0.171	+ 0.094
			FF				
			SIP	85.00	90.2	0.154	0
			Moderate	93.75	90.2	0.154	0
			Intermediate	97.50	90.2	0.154	0
			Stringent	99.25	90.2	0.154	0
			ESP				
0.6% S			SIP	86.67	55.8	0.096	0
5.4% A			Moderate	94.44	75.5	0.130	+ 0.034
			Intermediate	97.78	96.5	0.165	+ 0.069
			Stringent	99.33	124.0	0.212	+ 0.116
			FF				
			SIP	86.67	93.2	0.160	0
			Moderate	94.44	93.2	0.160	0
			Intermediate	97.78	93.2	0.160	0
			Stringent	99.33	93.2	0.160	0
			WS				
			SIP	86.67	289	0.495	0
			Moderate	94.44	338	0.577	+ 0.083

(continued)

TABLE 60 (continued)

System					Electrical energy consumption		
Standard boiler			Type and level of control	Control efficiency (percent)	Energy consumed by control device (kW)	% Increase in energy use over uncontrolled boiler *	% Change in energy use over SIP controlled boiler †
MW	Heat input (10^6 Btu/hr)	Type					
44.0	(150)	Spreader stoker	ESP				
	3.5% S 10.6% A		SIP	89.73	15.1	0.034	0
			Moderate	95.72	18.6	0.041	+ 0.008
			Intermediate	98.29	22.0	0.051	+ 0.016
			Stringent	99.49	26.7	0.061	+ 0.026
			FF				
			SIP	89.73	82.6	0.188	0
			Moderate	95.72	82.6	0.188	0
			Intermediate	98.29	82.6	0.188	0
			Stringent	99.49	82.6	0.188	0
			WS				
			SIP	89.73	93.0	0.211	0
			Moderate	95.72	162.2	0.368	+ 0.157
			Intermediate	98.29	231.2	0.525	+ 0.313
			ESP				
	0.9% S 6.9% A		SIP	81.54	35.3	0.082	0
			Moderate	92.31	48.8	0.113	+ 0.031
			Intermediate	96.92	63.2	0.143	+ 0.063
			Stringent	99.08	82.4	0.187	+ 0.107
			FF				
			SIP	81.54	77.6	0.177	0
			Moderate	92.31	77.6	0.177	0
			Intermediate	96.92	77.6	0.177	0
			Stringent	99.08	77.6	0.177	0
			WS				
			SIP	81.54	87.3	0.198	0
			Moderate	92.31	151.7	0.344	+ 0.146
			Intermediate	96.92	151.7	0.344	+ 0.146
			ESP				
	0.6% S 5.4% A		SIP	83.61	43.9	0.099	0
			Moderate	93.17	60.6	0.136	+ 0.038
			Intermediate	97.27	78.6	0.177	+ 0.079
			Stringent	99.18	102.1	0.232	+ 0.132
			FF				
			SIP	83.61	80.1	0.181	0
			Moderate	93.17	80.1	0.181	0
			Intermediate	97.27	80.1	0.181	0
			Stringent	99.18	80.1	0.181	0
			WS				
			SIP	83.61	90.1	0.205	0
			Moderate	93.17	156.9	0.358	+ 0.152
			Intermediate	97.27	224.0	0.508	+ 0.304

(continued)

TABLE 60 (continued)

System					Electrical energy consumption		
Standard boiler							
MW	Heat input (10^6 Btu/hr)	Type	Type and level of control	Control efficiency (percent)	Energy consumed by control device (kW)	% Increase in energy use over uncontrolled boiler *	% Change in energy use over SIP controlled boiler †
22.0	(75)	Chain grate stoker	ESP				
3.5% S 10.6% A			SIP	73.33	5.7	0.027	0
			Moderate	88.89	7.3	0.034	+ 0.007
			Intermediate	95.56	9.0	0.041	+ 0.015
			Stringent	98.67	11.2	0.051	+ 0.025
			FF				
			SIP	73.33	41.2	0.188	0
			Moderate	88.89	41.2	0.188	0
			Intermediate	95.56	41.2	0.188	0
			Stringent	98.67	41.2	0.188	0
			WS				
			SIP	73.33	46.4	0.211	0
			Moderate	88.89	80.7	0.368	+ 0.156
			Intermediate	95.56	115.0	0.522	+ 0.311
			Stringent	98.67	115.0	0.522	+ 0.311
			ESP				
0.9% S 6.9% A			SIP	52.00	10.1	0.044	0
			Moderate	80.00	16.6	0.075	+ 0.030
			Intermediate	92.00	23.5	0.106	+ 0.061
			Stringent	97.60	32.8	0.150	+ 0.103
			FF				
			SIP	52.00	38.4	0.174	0
			Moderate	80.00	38.4	0.174	0
			Intermediate	92.00	38.4	0.174	0
			Stringent	97.60	38.4	0.174	0
			WS				
			SIP	52.00	43.2	0.198	0
			Moderate	80.00	43.2	0.198	0
			Intermediate	92.00	75.2	0.341	+ 0.145
			Stringent	97.60	107.2	0.488	+ 0.290
			MC				
			SIP	52.00	25.6	0.116	0
			Moderate	80.00	25.6	0.116	0

(continued)

TABLE 60 (continued)

System					Electrical energy consumption		
Standard boiler			Type and level of control	Control efficiency (percent)	Energy consumed by control device (kW)	% Increase in energy use over uncontrolled boiler *	% Change in energy use over SIP controlled boiler †
Heat input MW	(10^6 Btu/hr)	Type					
Chain grate stoker (continued)							
			ESP				
0.6% S			SIP	57.45	12.7	0.058	0
5.4% A			Moderate	82.27	20.9	0.095	+ 0.037
			Intermediate	92.91	29.5	0.133	+ 0.076
			Stringent	97.87	40.9	0.188	+ 0.128
			FF				
			SIP	57.45	40.0	0.181	0
			Moderate	82.27	40.0	0.181	0
			Intermediate	92.91	40.0	0.181	0
			Stringent	97.87	40.0	0.181	0
			WS				
			SIP	57.45	45.2	0.205	0
			Moderate	82.27	45.2	0.205	0
			Intermediate	92.91	78.4	0.358	+ 0.151
			Stringent	97.87	111.8	0.508	+ 0.302
			MC				
			SIP	57.45	26.7	0.121	0
			Moderate	82.27	26.7	0.121	0
D. 8.8	(30)	Underfeed stoker					
			ESP				
3.5% S			SIP	73.21	2.2	0.024	0
10.6% A			Moderate	88.84	2.8	0.031	+ 0.007
			Intermediate	95.54	3.5	0.041	+ 0.015
			Stringent	98.66	4.3	0.048	+ 0.024
			FF				
			SIP	73.21	16.4	0.188	0
			Moderate	88.84	16.4	0.188	0
			Intermediate	95.54	16.4	0.188	0
			Stringent	98.66	16.4	0.188	0
			WS				
			SIP	73.21	59.6	0.678	0
			Moderate	88.84	59.6	0.678	0

(continued)

TABLE 60 (continued)

System					Electrical energy consumption		
Standard boiler			Type and level of control	Control efficiency (percent)	Energy consumed by control device (kW)	% Increase in energy use over uncontrolled boiler *	% Change in energy use over SIP controlled boiler †
MW	Heat input (10^6 Btu/hr)	Type					
Underfeed stoker (continued)							
			ESP				
	0.9% S		SIP	52.00	4.0	0.044	0
	6.9% A		Moderate	80.00	6.5	0.075	+ 0.028
			Intermediate	92.00	9.3	0.106	+ 0.060
			Stringent	97.60	13.0	0.147	+ 0.102
			FF				
			SIP	52.00	15.6	0.177	0
			Moderate	80.00	15.6	0.177	0
			Intermediate	92.00	15.6	0.177	0
			Stringent	97.60	15.6	0.177	0
			WS				
			SIP	52.00	30.5	0.348	0
			Moderate	80.00	30.5	0.348	0
			Intermediate	92.00	43.4	0.494	+ 0.146
			MC				
			SIP	52.00	10.4	0.118	0
			Moderate	92.00	10.4	0.118	0
			ESP				
	0.6% S		SIP	57.14	5.0	0.058	0
	5.4% A		Moderate	82.14	8.2	0.092	+ 0.036
			Intermediate	92.86	11.4	0.130	+ 0.073
			Stringent	97.86	16.0	0.181	+ 0.125
			FF				
			SIP	57.14	16.0	0.181	0
			Moderate	82.14	16.0	0.181	0
			Intermediate	92.86	16.0	0.181	0
			Stringent	97.86	16.0	0.181	0
			WS				
			SIP	57.14	18.0	0.205	0
			Moderate	82.14	31.3	0.355	+ 0.151
			Intermediate	92.86	31.3	0.355	+ 0.151
			Stringent	97.86	44.5	0.505	+ 0.301
			MC				
			SIP	57.14	10.7	0.122	0
			Moderate	82.14	10.7	0.122	0
			Intermediate	92.86	10.7	0.122	0

(continued)

TABLE 60 (continued)

System					Electrical energy consumption		
Standard boiler			Type and level of control	Control efficiency (percent)	Energy consumed by control device (kW)	% Increase in energy use over uncontrolled boiler*	% Change in energy use over SIP controlled boiler†
Heat input MW	(10^6 Btu/hr)	Type					
117.2	(400)	Pulverized coal					
			ESP				
3.5% S			SIP	91.64	37.4	0.032	0
10.6% A			Moderate	96.52	45.1	0.038	+0.007
			Intermediate	98.61	53.6	0.046	+0.014
			Stringent	99.58	64.4	0.055	+0.023
			FF				
			SIP	91.64	191.0	0.163	0
			Moderate	96.52	191.0	0.163	0
			Intermediate	98.61	191.0	0.163	0
			Stringent	99.58	191.0	0.163	0
			ESP				
2.3% S			SIP	92.49	50.5	0.043	0
13.2% A			Moderate	96.87	62.7	0.053	+0.01
			Intermediate	98.75	75.4	0.064	+0.021
			Stringent	99.62	91.9	0.078	+0.035
			FF				
			SIP	92.49	192.0	0.164	0
			Moderate	96.87	192.0	0.164	0
			Intermediate	98.75	192.0	0.164	0
			Stringent	99.62	192.0	0.164	0
			ESP				
0.9% S			SIP	85.00	90.2	0.077	0
6.9% A			Moderate	93.75	123.0	0.105	+0.028
			Intermediate	97.50	157.3	0.134	+0.057
			Stringent	99.25	202.7	0.173	+0.096
			FF				
			SIP	85.00	180.0	0.154	0
			Moderate	93.75	180.0	0.154	0
			Intermediate	97.50	180.0	0.154	0
			Stringent	99.25	180.0	0.154	0

(continued)

TABLE 60 (continued)

System					Electrical energy consumption		
Standard boiler			Type and level of control	Control efficiency (percent)	Energy consumed by control device (kW)	% Increase in energy use over uncontrolled boiler*	% Change in energy use over SIP controlled boiler†
MW	Heat input (10^6 Btu/hr)	Type					
Pulverized coal (continued)							
			ESP				
	0.6% S		SIP	86.67	112.6	0.096	0
	5.4% A		Moderate	94.44	152.6	0.130	+0.034
			Intermediate	97.78	195.2	0.167	+0.070
			Stringent	99.33	251.2	0.214	+0.118
			FF				
			SIP	86.67	186.0	0.159	0
			Moderate	94.44	186.0	0.159	0
			Intermediate	97.78	186.0	0.159	0
			Stringent	99.33	186.0	0.159	0
			WS				
			SIP	86.67	519.4	0.443	0
			Moderate	94.44	674.4	0.575	+0.132

* $\frac{\text{energy consumed}}{\text{heat input}} \times 100$

† $\frac{\text{energy consumed} - \text{SIP energy}}{\text{heat input} + \text{SIP energy}} \times 100$

increases from 55.8 to 124.0 kW (a 122 percent increase). A comparison of these increases indicates that it costs progressively more per unit of recovered dust as the efficiency requirement is increased. However, viewing these numbers from the perspective of the impact on effluent concentration, it is seen that the emissions are reduced about 20 times for less than a 2.5 times increase in energy requirement.

The increase in electricity demand is also borne out by the power consumption statistics for the ESP on the bases of coal sulfur content. For the same pulverized coal boiler at the stringent level of control, power requirements increase from 31.7 kW to 124.0 kW as sulfur content decreases from 3.5 to 0.6 percent to meet a similar overall efficiency requirement. It should also be noted that the baghouse becomes less energy intensive than the ESP at the stringnet control level for both pulverized and spreader stoker boilers burning 0.6 and 0.9 percent sulfur coal.

The significantly higher energy consumption for a wet scrubber is also shown in Table 60.

Taking all levels of control into consideration for all standard boilers, the precipitator is the least energy intensive (0.024 to 0.23 percent increase over uncontrolled) followed by the multitube cyclone (0.116 to 0.122 percent increase), fabric filter (0.16 to 0.19 percent increase), and the wet scrubber (0.2 to 0.7 percent increase over uncontrolled boilers). (It should be noted that the absolute electrical consumption figures are more important than the preceeding percentages when evaluating control system costs.)

The following is an example of the calculation of power requirements for an ESP controlling particulate emissions at the stringent level from a spreader stoker boiler burning 0.6 percent sulfur coal:

Example calculation:

(1) Fan power requirements:

$$P = 2.85 \times 10^{-4} \, Q_I \, \Delta P$$

(a) The air flow for the spreader stoker boiler is given as 1,778 acm/min (62,800 acfm) at 177°C (350°F) when burning 0.6 percent sulfur coal. Because of the lowered resistivity, a precipitator would be best placed upstream of the air heater where the temperatures average about 400°C (750°F). Consequently, the resulting flue gas flow rate will increase; i.e.,

$$(1{,}778 \text{ acm/min}) \left(\frac{273.1^\circ\text{C} + 400^\circ\text{C}}{273.1^\circ\text{C} + 177^\circ\text{C}}\right)$$

$$\cong 2{,}667 \text{ acm/min or } 94{,}200 \text{ acfm}$$

(b) A typical flange-to-flange pressure drop through an ESP is about 0.12 kPa (0.5 inches W.C.). Therefore, the power needed to meet the gas moving requirement as computed from Equation (1) becomes:

$$P = (2.85 \times 10^{-4})(9.42 \times 10^{4})\ 0.5 = 13.4 \text{ hp}$$

or by converting to kW

$$P = (13.4 \text{ hp})(0.7457 \text{ kW/hp}) = 10.0 \text{ kW}$$

(2) Power for energizing corona:

(a) At 0.6 percent S coal, W = 6.4 cm/sec (0.21 ft/sec) = 384 cm/min (12.6 ft/min)

(b) $W_k = W \ln\left(\frac{1}{Q}\right)$

(c) Required efficiency at the stringent level of control from Table 3-4 is 99.18 percent. Therefore Q, penetration, = 0.0082

(d) $W_k = 384 \ln (1/0.0082) = 1{,}845$ cm/min

or

$W_k = 12.6 \ln (1/0.0082) = 61$ ft/min

(e) $\frac{A}{V} = \frac{1}{W_k} \ln^2 \left(\frac{1}{Q}\right)$

$\frac{A}{V} = \frac{1}{61} \ln^2 \left(\frac{1}{0.0082}\right)$

$\frac{A}{V} = 0.381 = 381 \text{ ft}^2/1000 \text{ acfm}$

(f) Plate area $= \frac{381 \text{ ft}^2}{1000 \text{ acfm}} \times 94{,}200 \text{ acfm}$

$= 35{,}890 \text{ ft}^2 \; (3{,}334 \text{ m}^2)$

(g) By means of Equation 4 and assuming a power density, D, of 1.9 watts/ft^2 for a hot-side precipitator, the corona energizing power is calculated as follows:

$P = A\,D \times 10^{-3} = (35{,}890)(1.9)(10^{-3}) = 68.2 \text{ kW}$

(3) Auxiliary power:

$$P = 2.1 \times 10^{-4} \, (A)^{1.11} \qquad \text{(Equation 5)}$$

$$P = 2.1 \times 10^{-4} \, (35{,}890 \text{ ft}^2)^{1.11}$$

$$P = 23.9 \text{ kW}$$

(4) Total power consumption = fan + corona + auxiliary

Total Power = 10 kW + 68.2 kW + 23.9 kW

$\boxed{\text{Total power} \cong 102 \text{ kW}}$

In the above case, the energizing power is roughly the equivalent of an additional 0.9 kPa (3.5 inch W.C.) pressure loss across the ESP. It should also be noted that the 102 kW required by the ESP at the stringent level of control for the boiler/fuel combination cited in the illustration exceeds that required by a baghouse by about 27.5 percent. This effect is shown in Figure 37.

The dependence of ESP energy usage upon coal sulfur content is shown in Figures 38 through 41 for four coal-fired standard boilers. The difference in scale (kW — x-axis) for the chain grate and underfeed stoker boilers should be noted.

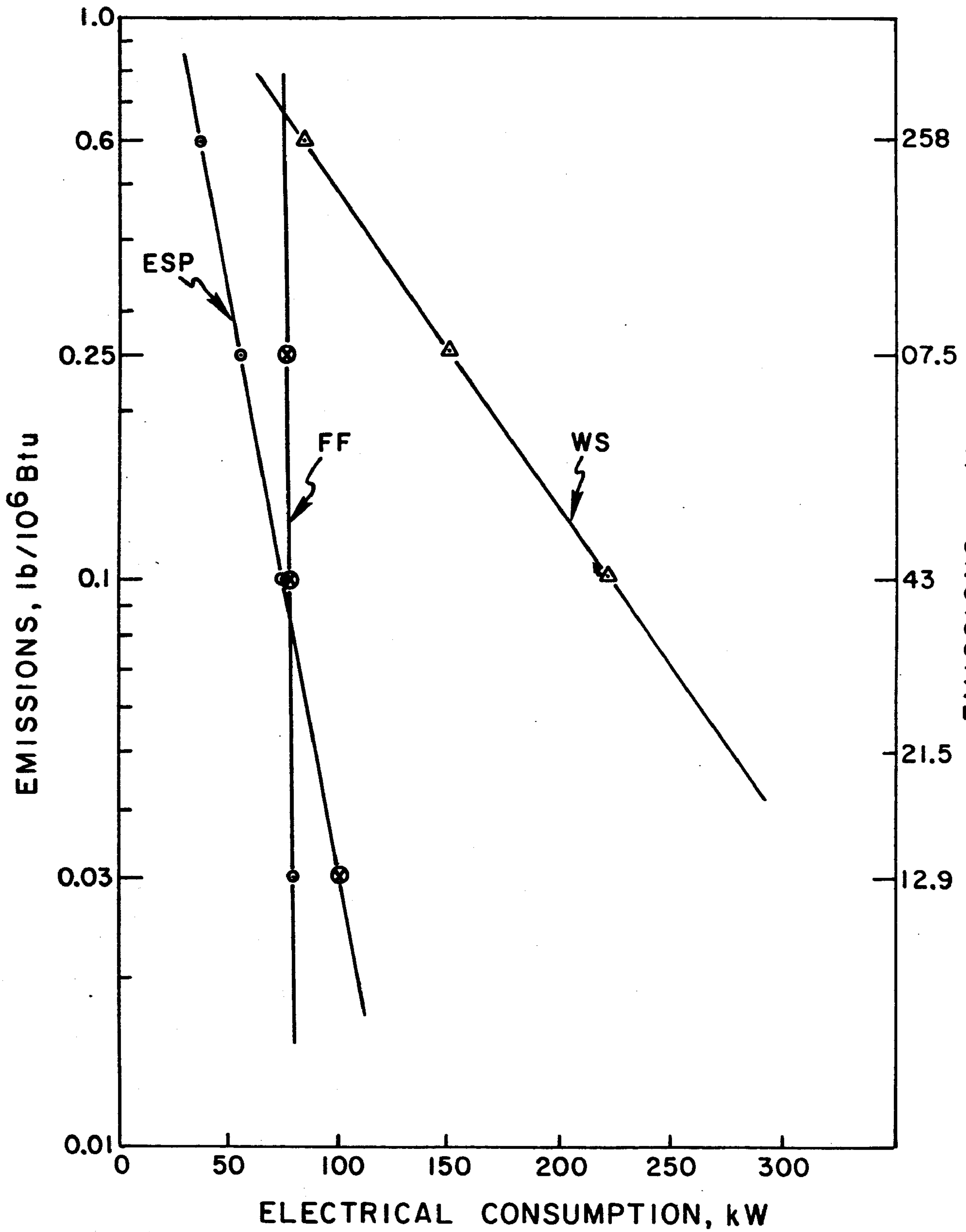

Figure 37. Electrical consumption of control equipment on the spreader stoker boiler burning 0.6 percent sulfur coal.

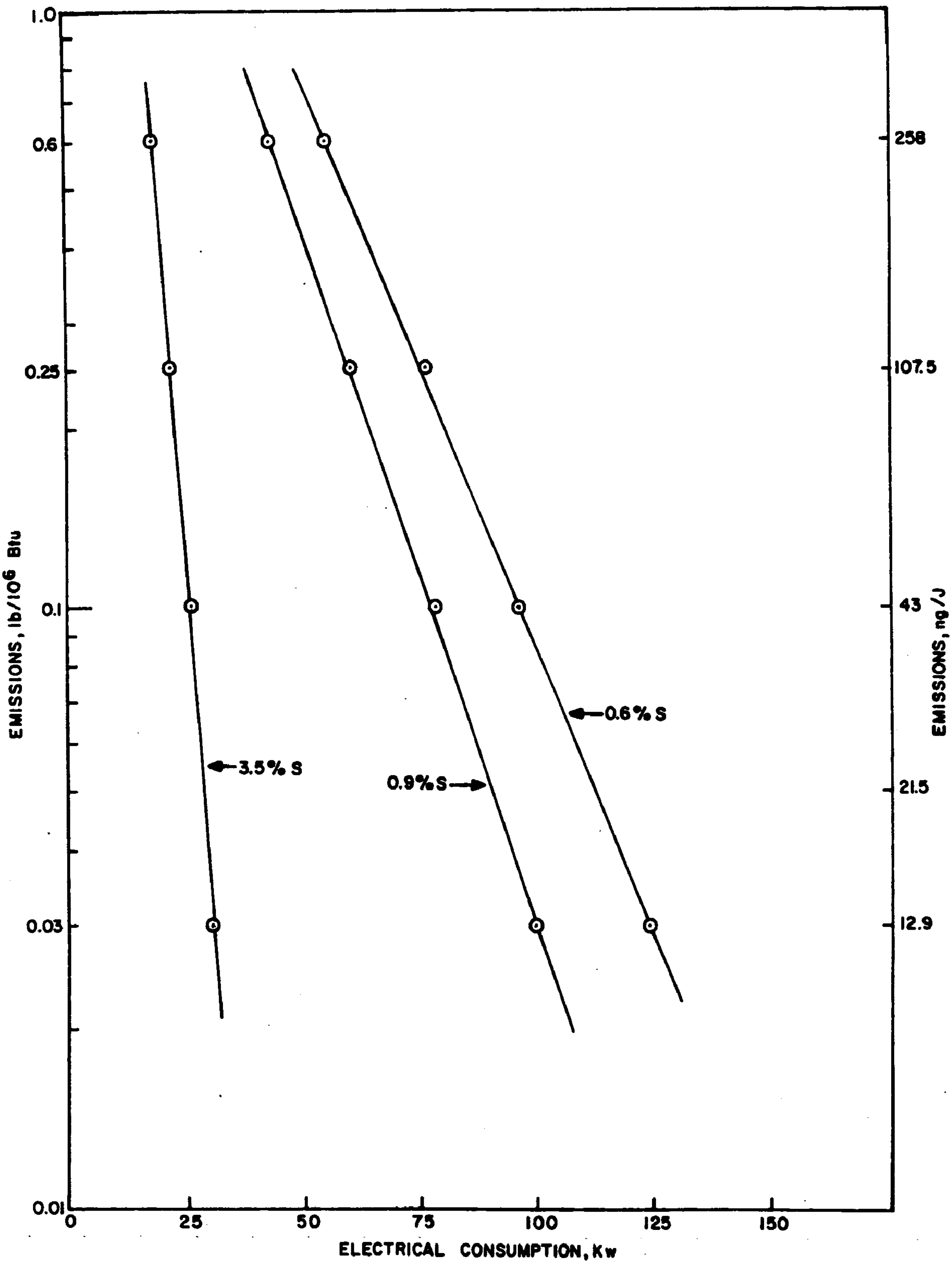

Figure 38. Electrical consumption of an electrostatic precipitator on the pulverized coal boiler burning three coals.

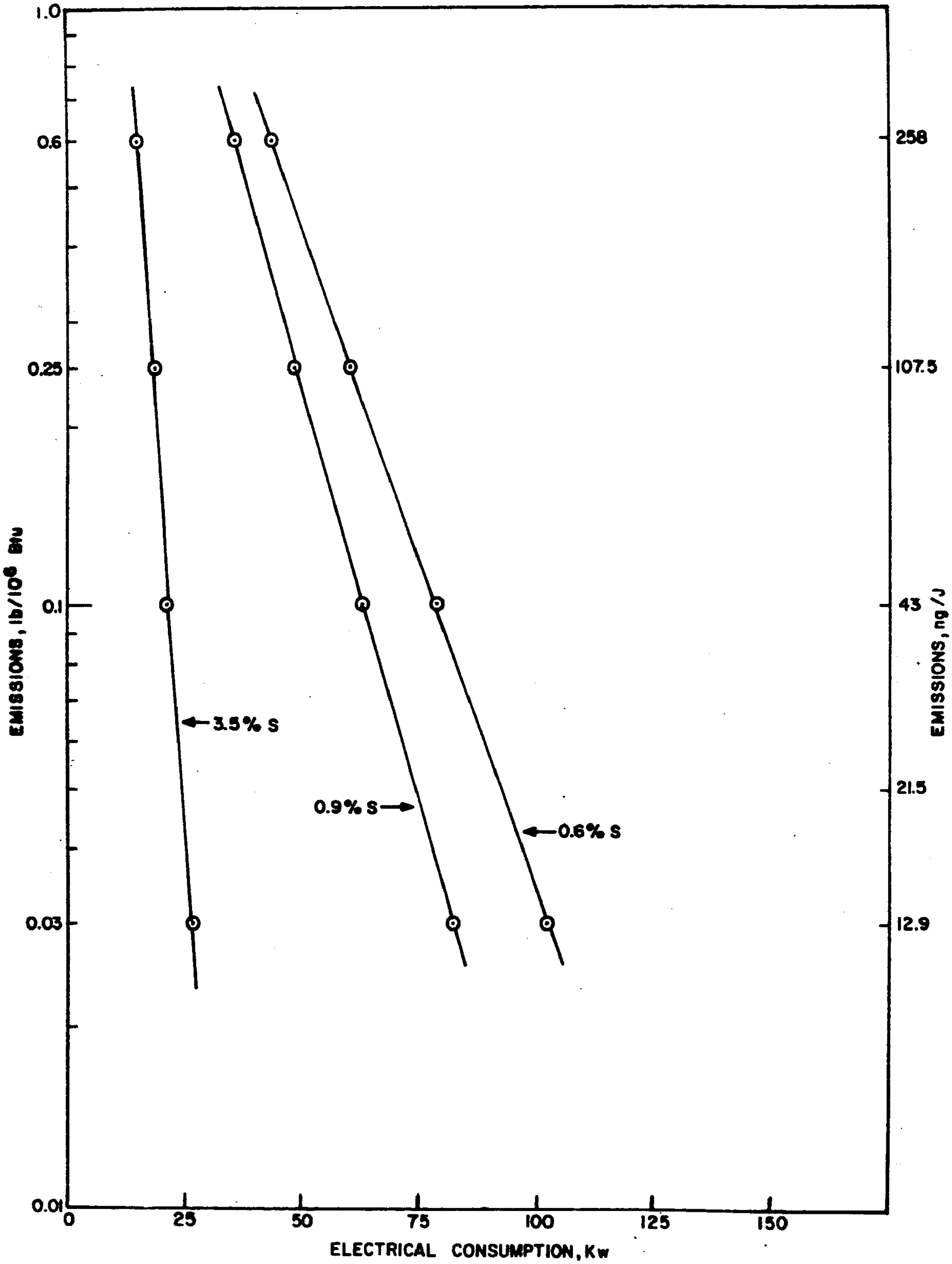

Figure 39. Electrical consumption of an electrostatic precipitator on the spreader stoker boiler burning three coals.

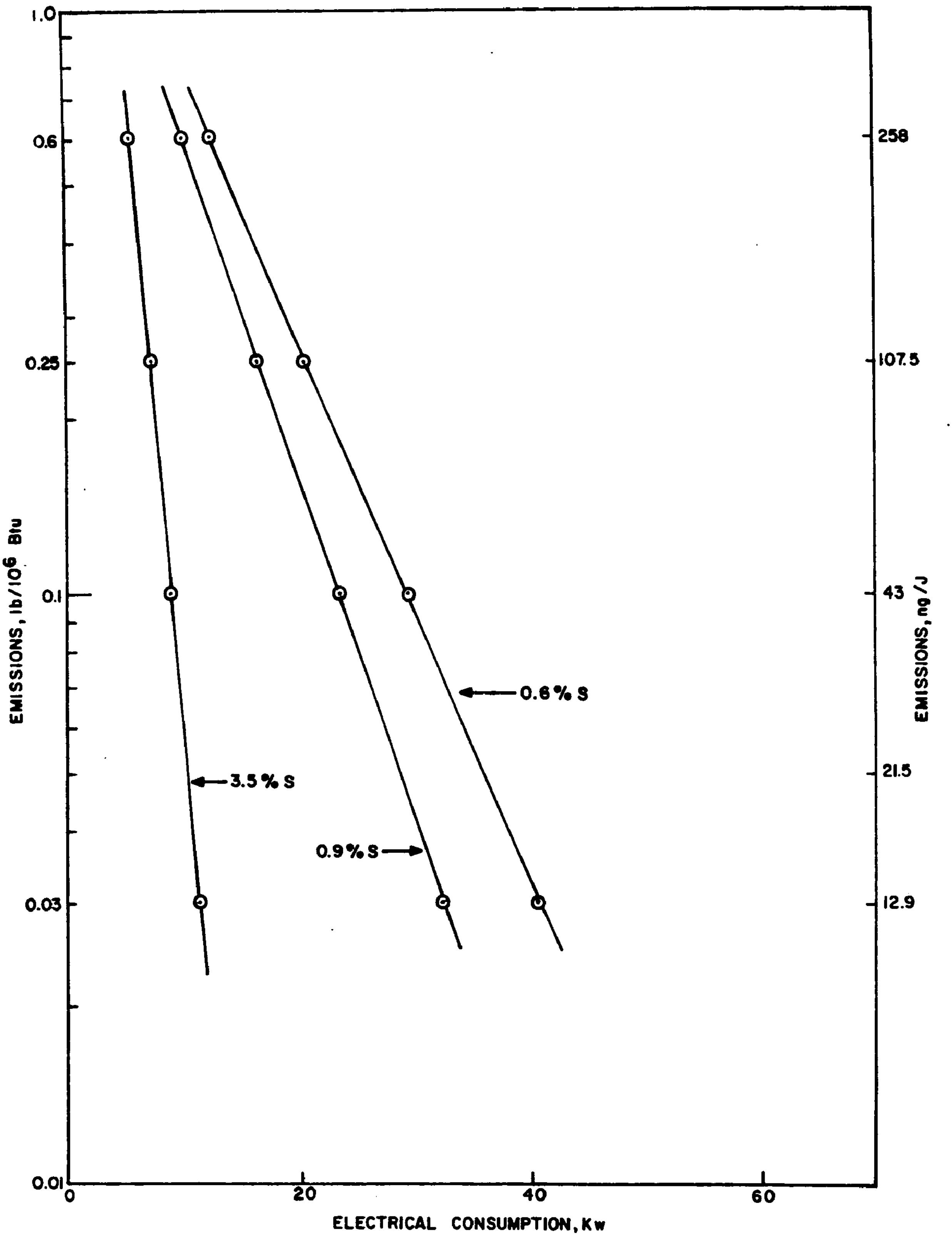

Figure 40. Electrical consumption of an electrostatic precipitator on the chain grate stoker boiler burning three coals.

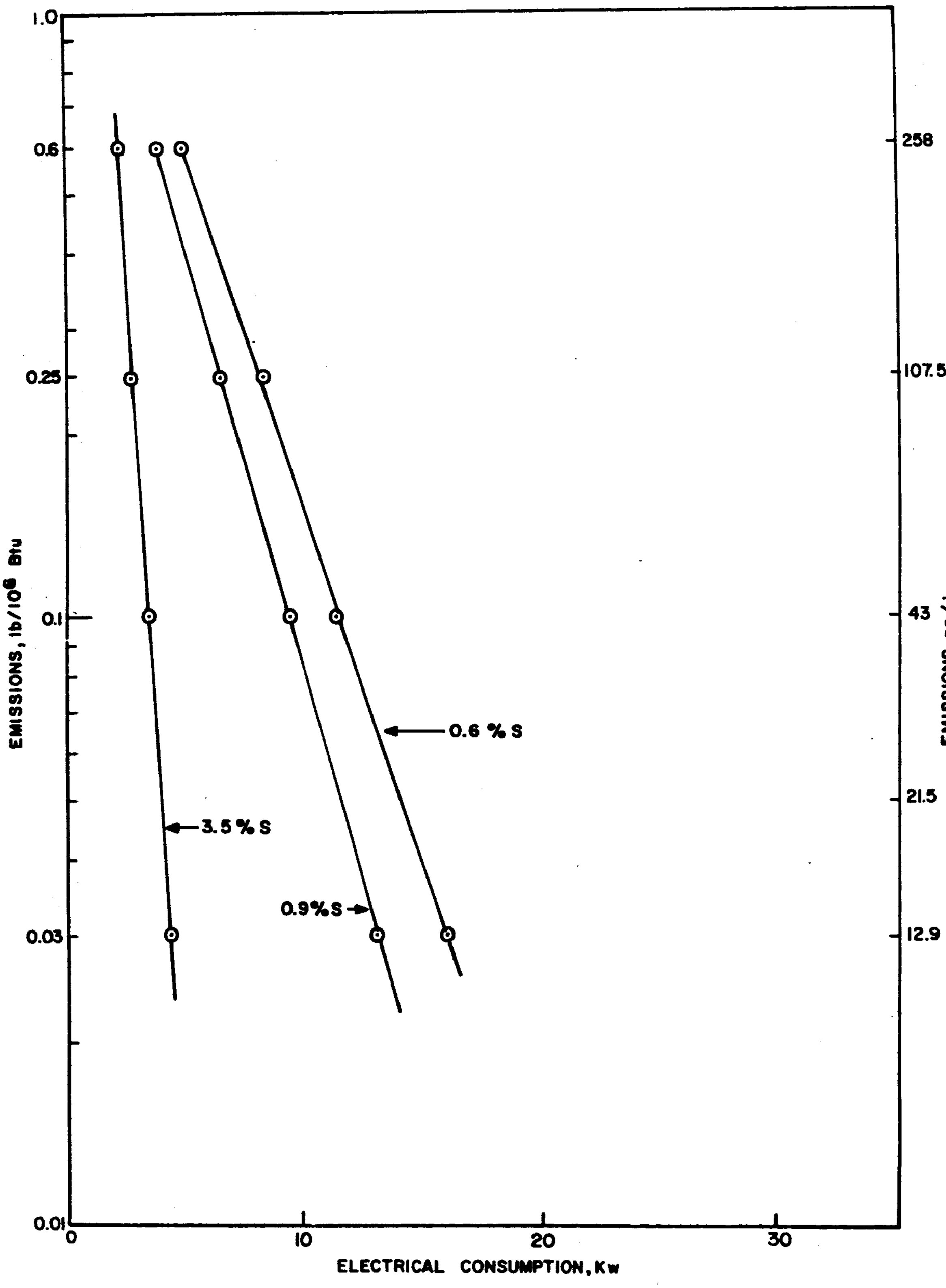

Figure 41. Electrical consumption of an electrostatic precipitator on the underfeed stoker boiler burning three coals.

Minimization of electrical energy consumption by particulate control equipment is important to the boiler operator and cannot be overemphasized. Sound operating procedures such as the monitoring of boiler parameters are normal practice and result in efficient overall plant operation. Parameters such as air and water temperature, air-to-fuel ratio, fuel feed rate, oxygen in the flue gas, and steam or kW production should be monitored closely to enable the boiler load to be accurately and efficiently increased or decreased. Maintenance of the boiler/turbine system as well as the particulate control device is essential to efficient operation and minimal energy consumption. Consistent and frequent boiler maintenance results in efficient fuel consumption while control equipment maintenance will ensure equipment longevity and will prevent excessive energy usage and correspondingly high operating costs.

Where it is allowed by local authorities, fuel switching offers one means of energy and fuel savings in that switching from coal to oil would likely mean bypassing the control equipment. This procedure would be employed during episode or stagnation periods and, therefore, energy savings would probably be small. The problem with fuel switching is that the additional equipment required for the switch may offset the potential energy savings that would be incurred when bypassing the particulate control equipment.

5.2.2 Modified and Reconstructed Facilities

It is most difficult to attempt to quantify the factors that would affect energy consumption at modified facilities. Electrical energy usage by the control devices mentioned previously would be the same unless installation problems resulted in greater pressure losses through frequently contorted connecting ductwork found in retrofit systems. Generally, the basic difference between a new and a retrofit installation will be reflected in the cost of the installation and not the energy consumption of the particulate control device.

5.3 ENERGY IMPACT OF CONTROLS FOR OIL-FIRED BOILERS

As can be noted in Table 31, the best system of control for the residual oil-fired boiler is an electrostatic precipitator for reasons mentioned in Section 2.0. For the purposes of this section, the maximum efficiencies listed in Tabel 31 are utilized in calculating power requirements.

Although there are limited data available concerning the sizing of ESP's for oil-fired boilers, the same procedures used for coal are employed with one exception. Whereas the power density used for the coal-fired case is 16.15 to 20.45 watts/m^2 (1.5 to 1.9 watts/ft^2), the power input, as determined from the Electrostatic Precipitator Manual,[7] is about 11.8 watts/m^2 (1.1 watts/ft^2) for the oil-fired system. The size of the precipitators required for the three levels of control (the SIP level and the intermediate level are the same) is very small and thus the power requirements which are shown in Table 61 are minor.

The fan electrical requirement is 6.6 hp (5.0 kW) as determined by Equation (1). The total energy requirements given in Table 62 are illustrated in Figure 42. The three levels of emission control show increases of less than 0.1 percent over uncontrolled boilers.

Factors relating to energy savings, retrofit installations and maintenance practices that were mentioned previously for coal-fired boilers also apply for the oil-fired boilers.

As will be noted from Table 31, distillate oil-fired boilers would not require control equipment if properly operated and maintained.

5.4 ENERGY IMPACT OF CONTROLS FOR GAS-FIRED BOILERS

Because of the minimal uncontrolled emission values for gas-fired units, particulate control would not be required and there would therefore be no additional energy consumption.

TABLE 61. DESIGN PARAMETERS AND ENERGY CONSUMPTION OF AN ELECTROSTATIC PRECIPITATOR ON THE RESIDUAL OIL-FIRED BOILER

Boiler type, heat input and fuel	Type and level of control	Control efficiency (percent)	W* (fpm)	SCA† ($ft^2/10^3$ acfm)	Plate‡ area (ft^2)	Power consumption	
						To energize Corona (kW)	Auxiliary (kW)
Residual oil 44 MW (150 10 Btu/hr)	ESP						
3.0% S	Moderate	30.5	5.134	71	3,316	3.6	1.7
	Intermediate and SIP	75.0	5.134	270	12,609	13.9	7.5
	Stringent	91.7	5.134	485	22,650	24.9	14.3

*To convert from fpm to cm/sec, multiply by 0.508

†To convert from $ft^2/10^3$ acfm to m^2/acmm, multiply by 3.28

‡To convert from ft^2 to m^2, multiply by 0.0929

TABLE 62. ELECTRICAL ENERGY CONSUMPTION FOR PARTICULATE CONTROL TECHNIQUES FOR RESIDUAL OIL-FIRED BOILERS

System					Electrical energy consumption		
Standard boiler			Type and level of control	Control efficiency (percent)	Energy consumed by control device (kW)	% Increase in energy use over uncontrolled boiler	% Change in energy use over SIP controlled boiler
MW	Heat input (10^6 Btu/hr)	Type					
44	(150)	Residual oil	ESP				
3.0% S			Moderate	30.50	10.3	0.023	-
			Intermediate and SIP	75.0	26.4	0.06	0
			Stringent	91.70	44.2	0.10	+0.04

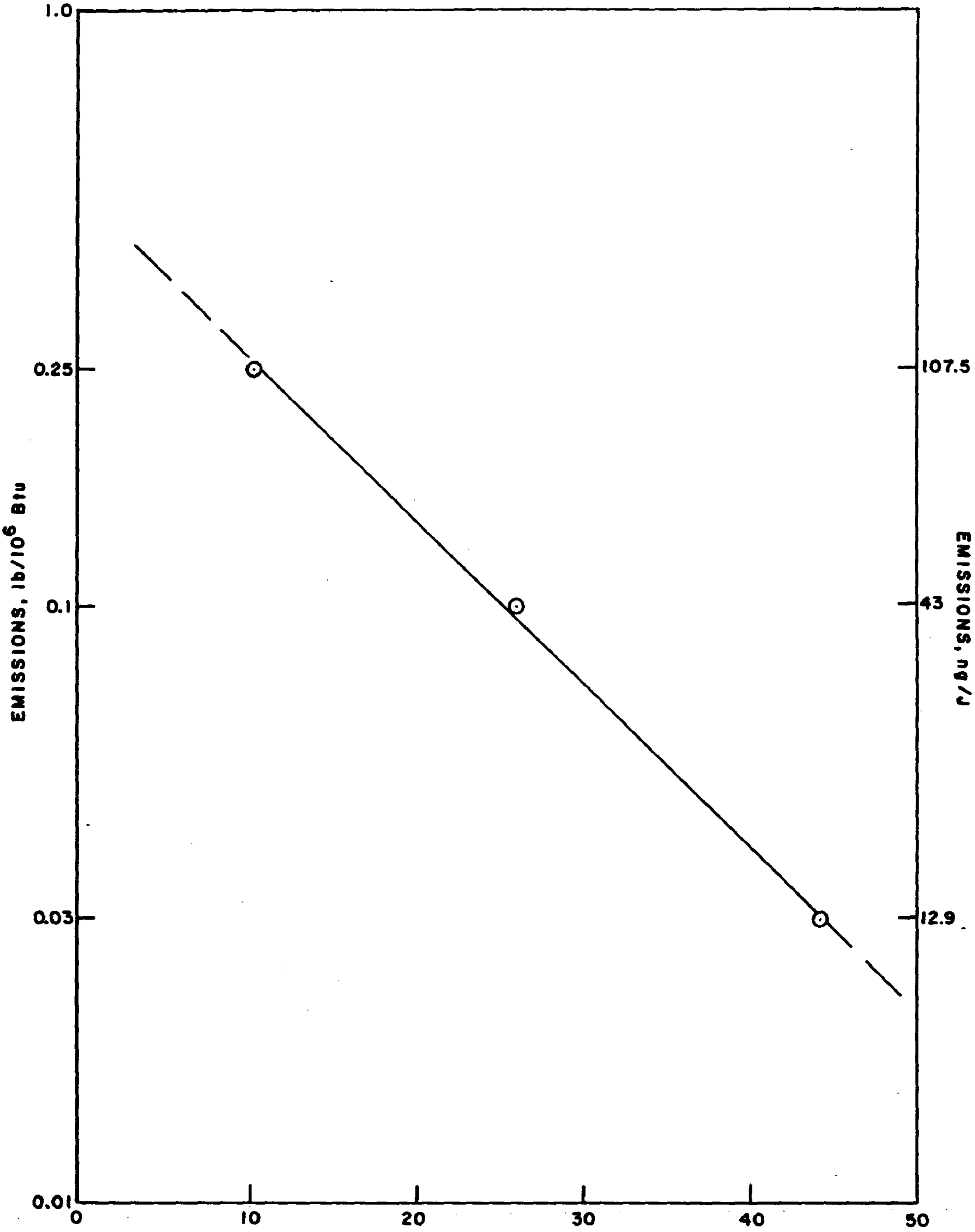

Figure 42. Electrical consumption of an ESP on a residual oil-fired boiler burning 3.0 percent S oil.

5.5 SUMMARY

Data presented in this section show that particulate control equipment would require a 0.02 to 0.7 percent increase in energy consumption over uncontrolled coal-fired boilers. Oil-fired boilers would require 0.02 to 0.1 percent additional energy. These percentages have been based upon the boiler input and one should look at actual electrical loads when evaluating energy impacts associated with varying levels of control.

These data show that the ESP is the least energy intensive control device at all levels of control when 3.5 percent S coal is burned. When the coal utilized is either 0.9 percent or 0.6 percent S, the baghouse becomes less energy intensive for pulverized and spreader stoker boilers at the stringent control level.

It should be stressed that certain assumptions have been made in the preceding analyses to simplify the computations. The use of a constant power density for cold and hot ESP systems would not exist in a real system since lower sulfur coals (higher resistivities) result in decreasing power densities necessitating larger collectors (plate area). However, it is felt that the overall trends indicated depict a fair representation of the systems evaluated.

5.6 REFERENCES

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7. Oglesby, S., Jr. op. cit. p. 373.

6.0 ENVIRONMENTAL IMPACT OF CANDIDATES FOR BEST SYSTEMS OF EMISSION REDUCTION

6.1 INTRODUCTION

The purpose of this section is to evaluate the environmental impacts of the candidate control technologies under consideration. Any reduction in stack gas particulate emissions will cause an increase in solid waste, for example, the effects of which must be fully assessed. These multiple and/or interrelated impacts can also result from the energy requirements of control equipment since more fuel must necessarily be burned to generate the required electrical power.

Also of obvious concern is whether particulate emission control systems will cause an increase in emissions of harmful pollutants (carcinogens, toxic trace elements, etc.).

Other impacts such as increased water, thermal, and/or noise pollution will also be addressed.

6.2 ENVIRONMENTAL IMPACTS OF CONTROLS FOR COAL-FIRED BOILERS

6.2.1 Air Pollution

The primary source of air pollutants from a fossil-fueled boiler operation is the flue gas exhaust stack. Other minor sources include emissions from ash handling, cooling tower drift or spray (where one is used), and coal storage, handling, and preparation facilities.

The primary air environmental impact resulting from particulate control will be beneficial in that the stack emissions will be reduced considerably. Accompanying the overall decrease in particulate emissions will be the corresponding reduction of the particulate/sulfate complex which is believed to have an adverse/synergistic effect on human health.[1] Table 63, which includes air impacts for the best systems of emission reduction under the subheading of "Primary Pollutants" shows particulate emission rates for all boiler/fuel/control level combinations. Units are given as g/sec (lb/hr) and ng/J (lb/10^6 Btu). The column entitled "Other Pollutants" refers to the "criteria" pollutants (sulfur dioxide, oxides of nitrogen, carbon monoxide, and hydrocarbons) and any deviations in their respective emission rates as a result of particulate control are indicated in the table. It has been determined, however, that particulate controls do not significantly affect the emissions of these criteria pollutants, although SO_2 adsorption on deposited fly ash layers on ESP plates or fabric filters may reduce its effluent concentration.

Emissions of other substances not included in either of the Primary Pollutants categories are listed as Secondary Pollutants with beneficial or adverse impacts. Secondary air pollutants could be trace metals or any chemicals used to treat the fuel or boiler feedwater that are exhausted through the stack as vapors, droplets or solids. Boiler feedwater chemicals can only

TABLE 63. AIR, WATER, AND SOLID WASTE POLLUTION IMPACTS FROM "BEST" PARTICULATE CONTROL TECHNIQUES FOR COAL-FIRED BOILERS

System: Standard boiler: Heat input MW (10^6 Btu/hr)	System: Standard boiler: Type and fuel	System: Control level (name/% reduction)	System: Type of control	Primary pollutants: Particulates: g/sec (lb/hr)	Primary pollutants: Particulates: ng/J (lb/MBtu)	Primary pollutants: Other pollutants*: Pollutant	Primary pollutants: Other pollutants*: Degree % change	Secondary pollutants†: Beneficial	Secondary pollutants†: Adverse (solid waste) g/sec (lb/hr)‡
117.2 (400)	Pulverized coal								
	3.5% S 10.6% A	Uncontrolled	-	363 (2,875)	3092 (7.19)	SO_2 CO NO_x HC	NA	NA	-
		SIP/91.66	ESP, WS or FF	30 (240)	258 (0.6)	NA	NA	NA	332 (2,635)
		Moderate/96.52	ESP or FF	13 (100)	107.5 (0.25)	NA	NA	NA	350 (2,775)
		Intermediate/98.61	ESP or FF	5 (40)	43 (0.10)	NA	NA	NA	358 (2,835)
		Stringent/99.58	ESP or FF	1.5 (12)	12.9 (0.03)	NA	NA	NA	361 (2,863)
	2.3% S 13.2% A	Uncontrolled	-	403 (3,198)	3440 (8.0)	SO_2 CO NO_x HC	NA	NA	
		SIP/92.50	ESP, WS, or FF	30 (240)	258 (0.6)	NA	NA	NA	373 (2,958)
		Moderate/96.88	ESP or FF	13 (100)	107.5 (0.25)	NA	NA	NA	391 (3,098)
		Intermediate/98.75	ESP or FF	5 (40)	43 (0.10)	NA	NA	NA	398 (3,158)
		Stringent/99.63	ESP or FF	1.5 (12)	12.9 (0.03)	NA	NA	NA	402 (3,186)
	0.9% S 6.9% A	Uncontrolled	-	202 (1,600)	1720 (4.0)	SO_2 CO NO_x HC	NA	NA	-
		SIP/85.0	ESP, WS, or FF	30 (240)	258 (0.6)	NA	NA	NA	172 (1,360)
		Moderate/93.75	ESP, WS, or FF	13 (100)	107.5 (0.25)	NA	NA	NA	189 (1,500)
		Intermediate/97.5	ESP or FF	5 (40)	43 (0.10)	NA	NA	NA	197 (1,560)
		Stringent/99.25	ESP or FF	1.5 (12)	12.9 (0.03)	NA	NA	NA	200 (1,588)

(continued)

TABLE 63 (continued)

System				Primary pollutants				Secondary pollutants[†]	
Standard boiler				Particulates		Other pollutants[*]			
Heat input MW (10^6 Btu/hr)	Type and fuel	Control level (name/% reduction)	Type of control	g/sec (lb/hr)	ng/J (lb/MBtu)	Pollutant	Degree % change	Beneficial	Adverse (solid waste) g/sec (lb/hr)[‡]
	0.6% S 5.4% A	Uncontrolled	-	227 (1,800)	1935 (4.5)	SO_2 CO NO_x HC	NA	NA	-
		SIP/86.67	ESP, WS, or FF	30 (240)	258 (0.6)	NA	NA	NA	197 (1,560)
		Moderate/94.44	ESP, WS, or FF	13 (100)	107.5 (0.25)	NA	NA	NA	214 (1,700)
		Intermediate/97.78	ESP or FF	5 (40)	43 (0.10)	NA	NA	NA	222 (1,760)
		Stringent/99.33	ESP or FF	1.5 (12)	12.9 (0.03)	NA	NA	NA	225 (1,788)
58.6 (200)	Pulverized coal								
	3.5% S 10.6% A	Uncontrolled	-	181 (1,436)	3,087 (7.18)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/91.64	ESP or FF	15 (120)	258 (0.6)	NA	NA	NA	166 (1316)
		Moderate/96.52	ESP or FF	6.2 (49)	107.5 (0.25)	NA	NA	NA	175 (1387)
		Intermediate/98.61	ESP or FF	2.4 (19)	43 (0.10)	NA	NA	NA	178.7 (1417)
		Stringent/99.58	ESP or FF	0.8 (6)	12.9 (0.03)	NA	NA	NA	180 (1430)
	0.9% S 6.9% A	Uncontrolled	-	100.8 (800)	1,720 (4.0)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/85.0	ESP or FF	15 (120)	258 (0.6)	NA	NA	NA	85.8 (680)
		Moderate/93.75	ESP or FF	6.3 (50)	107.5 (0.25)	NA	NA	NA	94.6 (750)
		Intermediate/97.50	ESP or FF	2.5 (20)	43 (0.1)	NA	NA	NA	98.4 (180)
		Stringent/99.25	ESP or FF	0.8 (6)	12.9 (0.03)	NA	NA	NA	100 (794)

(continued)

TABLE 63 (continued)

System				Primary pollutants				Secondary pollutants[†]	
Standard boiler				Particulates		Other pollutants[*]			
Heat input MW (10^6 Btu/hr)	Type and fuel	Control level (name/% reduction)	Type of control	g/sec (lb/hr)	ng/J (lb/MBtu)	Pollutant	Degree % change	Beneficial	Adverse (solid waste) g/sec (lb/hr)[‡]
	0.6% S 5.4% A	Uncontrolled	-	113.4 (900)	1,935 (4.5)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/86.67	ESP or FF	15 (120)	258 (0.6)	NA	NA	NA	98.4 (780)
		Moderate/94.44	ESP or FF WS	6.3 (50)	107.5 (0.25)	NA	NA	NA	107.2 (850) same and W.P.
		Intermediate/97.78	ESP or FF	2.5 (20)	43 (0.1)	NA	NA	NA	111 (880)
		Stringent/99.33	ESP or FF	0.8 (6)	12.9 (0.03)	NA	NA	NA	112.7 (894)
44 (150)	Spreader stoker								
	3.5% S 10.6% A	Uncontrolled	-	110 (876)	2511 (5.84)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/89.73	ESP or FF WS	11.4 (90)	258 (0.60)	NA	NA	NA	99 (786) same and W.P.
		Moderate/95.72	ESP or FF WS	4.7 (37.5)	107.5 (0.25)	NA	NA	NA	105.7 (838.5) same and W.P.
		Intermediate/98.29	ESP or FF WS	1.9 (15)	43 (0.10)	NA	NA	NA	108.6 (861) same and W.P.
		Stringent/99.49	ESP or FF	0.6 (4.5)	12.9 (0.03)	NA	NA	NA	109.9 (871.5)
	0.9% S 6.9% A	Uncontrolled	-	61 (487)	1398 (3.25)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/81.54	ESP or FF WS	11.4 (90)	258 (0.60)	NA	NA	NA	50 (397) same and W.P.
		Moderate/92.31	ESP or FF WS	4.7 (37.5)	107.5 (0.25)	NA	NA	NA	56.7 (449.5) same and W.P.
		Intermediate/96.92	ESP or FF WS	1.9 (15)	43 (0.10)	NA	NA	NA	59.5 (472) same and W.P.
		Stringent/99.08	ESP or FF	0.6 (4.5)	12.9 (0.03)	NA	NA	NA	60.8 (482.5)

(continued)

TABLE 63 (continued)

System				Primary pollutants				Secondary pollutants†	
Standard boiler				Particulates		Other pollutants*			
Heat input MW (10^6 Btu/hr)	Type and fuel	Control level (name/% reduction)	Type of control	g/sec (lb/hr)	ng/J (lb/MBtu)	Pollutant	Degree % change	Beneficial	Adverse (solid waste) g/sec (lb/hr)‡
	0.6% S 5.4% A	Uncontrolled	-	69 (548)	1574 (3.66)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/83.61	ESP or FF WS	11.3 (89.8)	258 (0.60)	NA	NA	NA	57.8 (458.2) same and W.P.
		Moderate/93.17	ESP or FF WS	4.7 (37.4)	107.5 (0.25)	NA	NA	NA	64.4 (510.6) same and W.P.
		Intermediate/97.27	ESP or FF WS	1.9 (15)	43 (0.10)	NA	NA	NA	67.2 (533) same and W.P.
		Stringent/99.18	ESP or FF	0.6 (4.5)	12.9 (0.03)	NA	NA	NA	68.5 (543.5)
22 (75)	Chain grate stoker								
	3.5% S 10.6% A	Uncontrolled	-	21.3 (169)	968 (2.25)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/73.33	ESP or FF WS	5.7 (45)	258 (0.60)	NA	NA	NA	15.6 (124) same and W.P.
		Moderate/88.89	ESP or FF WS	2.4 (18.8)	107.5 (0.25)	NA	NA	NA	18.9 (150.2) same and W.P.
		Intermediate/95.56	ESP or FF WS	0.9 (7.5)	43 (0.10)	NA	NA	NA	20.4 (161.5) same and W.P.
		Stringent/98.67	ESP or FF WS	0.3 (2.2)	12.9 (0.03)	NA	NA	NA	21 (166.8) same and W.P.
	0.9% S 6.9% A	Uncontrolled	-	11.9 (94)	538 (1.25)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/52.0	ESP, FF or MC WS	5.7 (45.1)	258 (0.60)	NA	NA	NA	6.2 (48.9) same and W.P.
		Moderate/82.0	ESP, FF or MC WS	2.1 (16.9)	107.5 (0.25)	NA	NA	NA	9.7 (77.1) same and W.P.

(continued)

TABLE 63 (continued)

System				Primary pollutants				Secondary pollutants†	
Standard boiler				Particulates		Other pollutants*			
Heat input MW (10^6 Btu/hr)	Type and fuel	Control level (name/% reduction)	Type of control	g/sec (lb/hr)	ng/J (lb/MBtu)	Pollutant	Degree % change	Beneficial	Adverse (solid waste) g/sec (lb/hr)‡
		Intermediate/92.0	ESP or FF WS	0.9 (7.5)	43 (0.10)	NA	NA	NA	10.9 (86.5) same and W.P.
		Stringent/97.6	ESP or FF WS	0.3 (2.3)	12.9 (0.03)	NA	NA	NA	11.6 (91.7) same and W.P.
	0.6% S 5.4% A	Uncontrolled	-	13.4 (106)	606 (1.41)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/57.45	ESP, FF or MC WS	5.7 (45.1)	258 (0.60)	NA	NA	NA	7.7 (60.9) same and W.P.
		Moderate/82.27	ESP, FF or MC WS	2.4 (18.8)	107.5 (0.25)	NA	NA	NA	11 (87.2) same and W.P.
		Intermediate/92.91	ESP or FF WS	0.9 (7.5)	43 (0.10)	NA	NA	NA	12.4 (98.5) same and W.P.
		Stringent/97.87	ESP or FF WS	0.3 (2.3)	12.9 (0.03)	NA	NA	NA	13 (103.7) same and W.P.
8.8 (30)	Underfeed stoker								
	3.5% S 10.6% A	Uncontrolled	-	8.4 (67)	963 (2.24)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/73.21	ESP or FF WS	2.3 (18)	258 (0.6)	NA	NA	NA	6.2 (49) same and W.P.
		Moderate/88.84	ESP or FF WS	0.9 (7.5)	107.5 (0.25)	NA	NA	NA	7.5 (59.5) same and W.P.
		Intermediate/95.54	ESP or FF WS	0.4 (3)	43 (0.10)	NA	NA	NA	8 (64) same and W.P.
		Stringent/98.66	ESP or FF	0.1 (0.9)	12.9 (0.03)	NA	NA	NA	8.3 (66.1)

(continued)

TABLE 63 (continued)

System				Primary pollutants				Secondary pollutants[†]	
Standard boiler		Control level (name/% reduction)	Type of control	Particulates		Other pollutants[*]		Beneficial	Adverse (solid waste) g/sec (lb/hr)[‡]
Heat input MW (10^6 Btu/hr)	Type and fuel			g/sec (lb/hr)	ng/J (lb/MBtu)	Pollutant	Degree % change		
	0.9% S 6.9% A	Uncontrolled	-	4.8 (38)	538 (1.25)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/52.0	ESP, FF or MC WS	2.3 (18.2)	258 (0.60)	NA	NA	NA	2.5 (19.8) same and W.P.
		Moderate/80.0	ESP, FF or MC WS	1.0 (7.6)	107.5 (0.25)	NA	NA	NA	3.8 (30.4) same and W.P.
		Intermediate/92.0	ESP or FF WS	0.4 (3.0)	43 (0.10)	NA	NA	NA	4.4 (35) same and W.P.
		Stringent/97.6	ESP or FF	0.1 (0.9)	12.9 (0.03)	NA	NA	NA	4.7 (37.1)
	0.6% S 5.4% A	Uncontrolled	-	5.3 (42)	602 (1.40)	SO_2 CO NO_x HC	NA	NA	NA
		SIP/57.14	ESP, FF or MC WS	2.3 (18)	258 (0.60)	NA	NA	NA	3 (24) same and W.P.
		Moderate/82.14	ESP, FF or MC WS	0.9 (7.5)	107.5 (0.25)	NA	NA	NA	4.4 (34.5) same and W.P.
		Intermediate/92.86	ESP, FF or MC WS	0.4 (3)	43 (0.10)	NA	NA	NA	4.9 (39) same and W.P.
		Stringent/97.86	ESP or FF WS	0.1 (0.9)	12.9 (0.03)	NA	NA	NA	5.2 (41.1) same and W.P.

[*] SO_2 = sulfur dioxide; NO_x = oxides of nitrogen; CO = carbon monoxide; HC = hydrocarbons. If none listed, none are affected (NA).

[†] Secondary pollutants could be other chemicals, trace metals, etc.

[‡] All numerical entries represent fly ash solid waste. W.P., where indicated, means potential for water pollution impact.

discharge via the stack when water tubes develop leaks due to severe corrosion. However, the above problem would not be related to the installation of particulate control equipment.

Trace elements may pose a serious health hazard since they concentrate largely on the surfaces of fly ash particles from which they may be readily desorbed following inhalation.[2] The process by which trace element concentrations are enriched on the smallest particles begins in the combustion zone with the volatilization of some chemical species containing the element. Downstream of the combustion zone, condensation and adsorption on particulate surfaces takes place. Surface area, a large fraction of which is represented by the smallest particles, plays an important role in determining rate of adsorption. Trace elements which are adsorbed on fly ash are antimony, arsenic, cadmium, chromium, copper, gallium, lead, mercury, nickel, polonium, selenium, thallium, and zinc.[3] Because of the fact that installation of some particulate control equipment will result in a higher proportion of fine particulate matter to be discharged to the atmosphere, the fraction of inhalable trace metal-bearing solids in the effluent will be higher. However, the net impact of the control equipment should be to reduce the atmospheric concentrations for these substances.

6.2.2 Water Pollution

The potential sources for water pollution at a fossil-fuel facility are ash handling systems, wet scrubber flue gas cleaning systems, boiler feedwater treatment, boiler blowdown, and boiler system equipment cleaning. The last three items, which are unrelated to pollution control operations, are not considered in this report. Ash handling, when carried out on a dry basis, is discussed under solid waste impact. However, if the ash is transported to a settling pond by a hopper sluicing system, it may generate water pollution problems at the storage site.

Wet scrubbers used for particulate control will produce significant quantities of liquid waste which may be discharged to an ash settling pond or piped to a local water treatment plant after solids removal treatment. The quantities discharging from conventional boiler facilities are difficult to predict since these systems often use differing liquid-to-gas (L/G) ratios as well as different degrees of recirculation. A Venturi scrubber on a pulverized coal boiler (3.5 percent sulfur) operating at an L/G ratio of 0.9 liters/m^3 (7 gal/1000 ft^3) with no recirculation will discharge about 2000 liters/min (525 gal/min). Usually this discharge is pumped to a settling pond where the fly ash settles to the bottom and the liquid is either discharged, evaporated, or recycled. Pond liners may be used to prevent leaching of any metals or chemicals into the soil and surrounding water table. Although intrusion upon a local water body or supply is always possible, good operating procedures can minimize this potential pollution impact. Any water pollution impacts are designated in Table 63 as Seconaary Particulates, where W.P. means potential for water pollution.

Since the properties of ash pond discharge waters differ from plant to plant, it is unreasonable to specify average values. Thus, Table 64 shows the concentration ranges expected for some of the more important chemical constituents.[4]

6.2.3 Solid Waste

The greatest environmental effect of particulate control systems will be that of increased solid waste generation and its resulting impact due to handling and disposal. However, it must be realized that without particulate

TABLE 64. PROPERTIES OF ASH POND DISCHARGE WATERS[4]

Water parameter	Range of concentration, mg/ℓ
Total solids	300–3500
Total dissolved solids	250–3300
Total suspended solids	25–100
Oil and grease	0–15
Hardness	200–750
Alkalinity	30–400
SO_4	100–300
Al	0.2–5.3
Cr	0.1
Na	20–173
NH_3	0.1–2
NO_3	0.1–6.1
Cl	20–2000
Cu	0.1–0.3
Fe	0.02–2.9

control, solid wastes appear as stack emissions which are equally or more detrimental to human health.

The amounts of solid waste generated at the various control levels for all boiler/fuel combinations are indicated in Table 63 as Secondary Pollutants (adverse impact) with units of g/sec (lb/hr). These amounts are, as expected, inversely proportional to the efficiencies required for each level of emission reduction.

The percentage increase in fly ash collection compared to that for the boiler controlled at the SIP level of 258 ng/J (0.6 lb/10^6 Btu) ranges from about 8 to 88 percent depending on boiler and fuel types, and degree of control. The 88 percent figure refers to the underfeed stoker boiler burning coal containing 0.9 percent sulfur and 6.9 percent ash and collecting 2.5 g/sec (19.8 lb/hr) and 4.7 g/sec (37.1 lb/hr) at the SIP and stringent levels, respectively.

The primary method of fly ash disposal is by landfilling, and as with settling ponds, liners and proper operating procedures, can minimize runoff or leaching into the water table. Aside from outright disposal, other solutions to the fly ash problem are its utilization in road embankments and as a component of concrete mixtures. However, fly ash application in the United States has lagged behind the European countries. In 1969, Great Britain and France used 42 and 55 percent, respectively, of their total fly ash production, as compared to only 9 percent for the United States.[5]

6.2.4 Other Environmental Impacts

Other potential environmental impacts arising from increased particulate control are noise generation from fans, compressors, pumps, electrode rappers, and/or cooling towers. The above impacts would have to be examined on a case-by-case basis to accurately determine their absolute effect on the surrounding community.

6.2.5 Environmental Impact on Modified and Reconstructed Facilities

The environmental impacts associated with retrofit installations are essentially the same as those for new facilities. These impacts, however, may be more serious depending upon the age of the plant and the equipment in use. For example, in the case of a retrofit installation, it is often necessary to operate within adverse space and geometry constraints such that optimum collection systems are more difficult to install.

6.3 ENVIRONMENTAL IMPACTS OF CONTROLS FOR OIL-FIRED BOILERS

The impacts of oil-fired facilities on the environment are essentially the same as those for coal-fired plants except that they are less severe due to the much lower uncontrolled ash emissions.

However, although the quantities of ash produced by an oil-fired plant are much smaller than those for a coal-fired plant, the ash-settling characteristics are more unfavorable in the case of oil because of its much smaller size properties.

On the positive side, because the vanadium content of oil fly ash is potentially toxic to aquatic life, even partial collection will result in an overall beneficial impact. It has been found in some cases that recycling oil fly ash to the furnace increases combustion efficiency and eliminates the ash disposal problem.

6.4 ENVIRONMENTAL IMPACTS OF CONTROLS FOR GAS-FIRED BOILERS

Due to the fact that gas-fired boilers exhibit inherently low uncontrolled emission rates and therefore do not require particulate control, there will be no recognized environmental impacts at the present time.

6.5 SUMMARY OF MAJOR ENVIRONMENTAL IMPACTS OF CONTROL TECHNIQUES

The primary environmental impact of more stringent particulate control requirements will be the added requirement for solid waste disposal. One must consider the relative impacts of uncontrolled stack emissions and the requirements for solid waste disposal.

The potential impact of solid waste disposal is dependent on such factors as land availability, available transportation routes, leaching of elements into ground-water supplies, runoff into water bodies used for recreational purposes, and whether or not the potential for fly ash utilization becomes more fully realized.

Considering all factors, it appears that the environment can only benefit from increased particulate control at the stack since fly ash disposal as solid or liquid wastes is a controllable process.

The environmental impact of the increased fuel usage required to provide the energy necessary to operate particulate control equipment is difficult to assess, although power supplied by large utility plants will likely result in minimal environmental impact because utility plants will probably be well controlled.

6.6 REFERENCES

1. Stern, A. C., et al. Fundamentals of Air Pollution. Academic Press, Inc. 1973. pp. 135-136.

2. Surprenant, N. F., et al. Preliminary Emissions Assessment of Conventional Stationary Combustion Systems - Volume II - Final Report. EPA-600/2-76-046b. March 1976. pp. 115-126.

3. Ibid. p. 123, Table 40.

4. Ibid. p. 138, Table 47.

5. Ibid. p. 136.

7.0 EMISSION SOURCE TEST DATA

7.1 INTRODUCTION

The purpose of this section is threefold:

- To describe fully any new source test data that have become available during the conduct of this industrial boiler technical assessment.
- To elaborate upon the test data and associated test methods presented in Section 2.0.
- To discuss the relative accuracies of the various test methods available for particulate sampling with respect to the three levels of emission control.

The selection of a given test method depends on numerous factors such as the pollutant to be sampled, the fuel burned, the temperature and pressure of the pollutant stream, the sampling location, the presence of corrosive substances, and the ultimate data application; i.e., to demonstrate compliance with specified emission regulations, to determine the efficiency of a given control device (performance test), or to determine whether vendor-guaranteed emission levels are being achieved (acceptance tests).

The application of test data may also be a decisive factor in deciding who conducts the source test. Organizations such as EPA and State agencies, private consulting companies, equipment manufacturers, source personnel, or combinations of the above are the groups by whom test data are usually procured.

Regardless of test classification or the testing group, efforts are normally made to obtain accurate and realistic information over the measurement period. Ideally, sampling should be performed in locations where there are minimum distortions or perturbations in gas stream flow profiles and where contaminant concentrations are uniform over the sampled cross section.

In actual practice, such ideal conditions seldom prevail in the field due to the absence of lengthy, straight runs of duct and the presence of elbows, tees, dampers or baffles that may lead to asymmetry in both velocity and concentration profiles. Hence there is a need to sample at many points within the test cross section to obtain a representative measure of pollutant concentration.

7.2 EMISSION SOURCE TEST DATA FOR COAL-FIRED BOILERS

Test data provided in Section 2.0 have been reviewed and an attempt has been made to further clarify or supplement this information. The following discussion provides further explanation of the former data.

Table 16 provided source test data for a number of coal-fired utility boilers controlled by electrostatic precipitators (ESP). The raw data constituting the bases for Table 16 are presented in this section in Tables 65 and 66. Boiler design parameters and test data are shown in Table 65 for the 10 surveyed utilities while fuel compositions are given in Table 66.

Table 65 shows pertinent design information such as boiler size, fuel consumption rate, furnace type, coal-firing method and control equipment operating and performance parameters at the time of the emission test as compared to those specified in the design criteria. The fuel data, Table 66, provide a good geographical sampling of coals burned in this country and the

TABLE 65. DETAILED EMISSION SOURCE DATA FOR INFORMATION PRESENTED IN TABLE 16

Station	Boiler data					Control equipment data									Particulate emission rate, $lb/10^6$ Btu
	Boiler No.	Size MW	Fuel consumption, tons/hr: Design	Fuel consumption, tons/hr: Average	Firing method	Primary	Manuf.	Outlet Temp. °F	Critical[a] parameter	Flow rate, acfm: Design	Flow rate, acfm: Test	Overall efficiency, percent: Design	Overall efficiency, percent: Test	Velocity, ft/sec	
AMERICAN ELECTRIC POWER, CANTON, OHIO															
Amos	3	1300	485	-	Front and rear	ESP	Koppers	328	403	$4.41x10^6$	$4.477x10^6$	99.75	99.67	5.44	0.04
Big Sandy	1	280	105	-	Front and rear	ESP	Koppers	300	223	950,000	853,300	98.5	98.5	6.3	0.24
	2	600	300	-	Front and rear	ESP	RC	360	153	$2.79x10^6$	$2.93x10^6$	98.5	98.2	6.3	0.17
Clinch River	1	240	80	-	Top	ESP	Koppers	310	963	900,000	850,000	99.7	99.7	3.09	0.05
	2	240	80	-	Top	ESP	Koppers	310	963	900,000	850,000	99.7	99.5	3.09	0.05
	3	240	80	-	Top	ESP	Koppers	310	963	900,000	850,000	99.7	99.5	3.09	0.05
Gavin	1	1300	485	-	Front and rear	ESP	Koppers	340	403	$4.41x10^6$	$4.429x10^6$	99.75	99.87	5.44	0.013
	2	1300	485	-	Front and rear	ESP	Koppers	340	403	$4.41x10^6$	$4.429x10^6$	99.75	99.77	5.44	0.014
Glen Lyn	5	105	48	-	Front	ESP	Am. Std.	315	607	509,000	527,000	99.7	99.9	4.09	0.003
	6	240	80	-	Front	ESP	Am. Std.	310	967	900,000	850,000	99.7	99.9	4.12	0.001
Kanawha River	1	210	80	-	Top	ESP	Buell	317	315	775,000	734,000	98.5	99.75	4.94	0.03
	2	210	80	-	Top	ESP	Buell	320	315	775,000	734,000	98.5	99.75	4.94	0.03
Tanners Creek	1	150	60	-	Top	ESP	RC	280	1045	640,000	312,000	99.9	99.7	3.1	0.01
	2	150	60	-	Top	ESP	RC	280	1045	640,000	312,000	99.9	99.7	3.1	0.01
CLEVELAND ELECTRIC ILLUMINATING CO., CLEVELAND, OHIO															
Eastlake	5	680	230	164	Front	ESP	RC	285	209	$2.15x10^6$	-	99.5	98.4	6.95	0.02 gr/scf
CONSUMERS POWER CO., JACKSON, MICHIGAN															
D. E. Karn	1	265	159	111.3	Tang.	2-ESPs	E.E.	315	245	$1.172x10^6$	$1.01x10^6$	97.0	99	5.53	0.026 gr/scf
	2	265	125.1	110.9	Front	2-ESPs	E.E.	315	245	$1.172x10^6$	$1.01x10^6$	97.0	99	5.53	0.026 gr/scf
J. R. Whiting	1	100	52	42	Front	ESP	Am. Std.	285	320	400,000	362,000	99	99.6	4.75	0.006 gr/scf
	2	100	52	42	Front	ESP	Am. Std.	285	320	475,000	351,000	99	99.6	4.75	0.036 gr/scf
	3	125	60	52.4	Front	ESP	Am. Std.	300	320	-	430,000	99	99.6	4.75	0.009 gr/scf

(continued)

TABLE 65 (continued)

Station	Boiler data: Boiler No.	Size MW	Fuel consumption, tons/hr: Design	Fuel consumption, tons/hr: Average	Firing method	Control equipment data: Primary	Manuf.	Outlet Temp. °F	Critical[a] parameter	Flow rate, acfm: Design	Flow rate, acfm: Test	Overall efficiency, percent: Design	Overall efficiency, percent: Test	Velocity ft/sec	Particulate emission rate lb/10⁶ Btu
J. H. Campbell	1	265	132.5	108.6	Tang.	2-ESPs	Buell	315	206	1,177,200	1.03×10^6	97	-	5.19	est: 0.0354 gr/scf
	2	385	170	160.2	Front and rear	2-ESPs	Buell	300	500	1,491,700	1,061,400	98	-	3.19	0.015 gr/scf
	3	800	300	210	Front and rear	ESP	Buell	305	640.4	3.4×10^6	-	98.58-99.32	-	5.83	0.06 gr/scf
DUKE POWER CO., CHARLOTTE, NORTH CAROLINA[b]															
Allen	1	166	56	-	Tang.	ESP	RC	308	150.38	532,000	677,459	99	98.41	5.5	0.1547
	2	165	56	-	Tang.	ESP	RC	308	150.38	532,000	637,455	99	97.35	5.5	0.2332
	3	275	91	-	Tang.	ESP	RC	630	269.57	1.25×10^6	1,177,648	99.2	97.65	5.94	-
	4	275	91	-	Tang.	ESP	RC	630	269.57	1.25×10^6	1,176,140	99.2	98.18	5.94	-
	5	275	91	-	Tang.	ESP	RC	630	269.57	1.25×10^6	1,055,527	99.2	97.88	5.94	-
Belews Creek	1	1140	360	-	Opposed PCOP	ESP	RC	260	304.56	3.2×10^6	3,930,530	99.7	97.38	5.25	0.09
	2	1140	360	-	Opposed PCOP	ESP	RC	260	304.56	3.2×10^6	3,244,601	99.7	91.34	5.25	-
Buck - 3	5&6	40	17	-	Tang.	ESP	Buell	695	239.29	337,000 ea	-	99	-	5.4 ea	-
- 4	7	40	17	-	Tang.	ESP	Buell	725	239.29	337,000	-	99	-	5.4	-
- 5	8	125	48	-	Tang.	ESP	Buell	625	237.94	640,000	-	99.08	-	5.1	-
- 6	9	125	48	-	Tang.	ESP	Buell	632	237.94	640,000	576,478	99.08	99.65	5.1	0.0459
Cliffside	1	40	17	-	Tang.	ESP	Buell	732	239.29	337,000	287,395	99	99.2	4.5	0.042
	2	40	17	-	Tang.	ESP	Buell	756	239.29	337,000	293,413	99	98.3	4.5	0.18
	3	65	28	-	Tang.	ESP	RC	648	218.7	400,000	362,301	99	99.18	5.5	0.0943
	4	65	28	-	Tang.	ESP	RC	655	218.7	400,000	396,925	99	98.86	5.5	0.1331
	5	572	238	-	Tang.	ESP	RC	263	211.15	1.78×10^6	1,613,413	99.5	99.29	5.7	0.0485
Dan River	1	70	30	-	Tang.	ESP	RC	622	216.42	402,000	360,674	99	98.73	5.52	0.1347
	2	70	30	-	Tang.	ESP	RC	644	216.42	402,000	378,509	99	99.55	5.52	0.083
	3	150	55	-	Tang.	ESP	Buell	300	296.07	535,000	492,954	99.2	98.93	5.0	0.0817
Lee	1	90	40	-	Tang.	ESP	RC	622	222.22	540,000	541,531	99	99.15	5.4	0.10
	2	90	40	-	Tang.	ESP	RC	622	222.22	540,000	-	99	-	5.4	0.11
	3	165	59	-	Tang.	ESP	Buell	622	230.4	825,000	740,525	99	99.23	4.6	0.12

(continued)

TABLE 65 (continued)

Station	Boiler data: Boiler No.	Size MW	Fuel consumption, tons/hr: Design	Average	Firing method	Control equipment data: Primary	Manuf.	Outlet Temp. °F	Critical[a] parameter	Flow rate, acfm: Design	Test	Overall efficiency, percent: Design	Test	Velocity, ft/sec	Particulate emission rate lb/10^6 Btu
Marshall	1	350	117	-	Tang.	ESP	Buell	260	174.39	1.09×10^6	1,145,937	99.5	99.24	6.1	0.11
	2	350	117	-	Tang.	ESP	Buell	260	174.39	1.09×10^6	1,085,205	99.5	93.61	6.1	0.10
	3	650	208	-	Tang.	ESP	RC	260	261.82	2.2×10^6	1,662,278	99.7	98.96	4.07	0.1195
	4	650	208	-	Tang.	ESP	RC	260	261.82	2.2×10^6	-	99.7	-	4.07	-
Riverbend - 4	7	100	41	-	Tang.	ESP	Buell	640	232.62	585,000	-	99.03	99.56	5.2	-
- 5	8	100	41	-	Tang.	ESP	Buell	640	232.62	585,000	483,538	99.03	99.59	5.2	0.0467
- 6	9	133	52	-	Tang.	ESP	Buell	614	235.2	675,000	-	99.06	99.74	5.1	-
- 7	10	133	52	-	Tang.	ESP	Buell	614	235.2	675,000	587,556	99.06	99.65	5.1	0.0421
GULF POWER CO., BIRMINGHAM, ALABAMA															
Crist	4	94	32.1	16.9	Tang.	2-ESPs hot/cold	Buell	300	257/179	515×10^3 290×10^3	-	99.1	99.5	4.48 4.675	0.033
	5	94	32.15	16.8	Tang.	2-ESPs hot/cold	Buell	300	257/179	515×10^3 290×10^3	-	99.1	98.9	4.48 4.675	0.082
	6	370	125	79.1	Tang.	ESP	Buell	268	137	505,000	-	98.0	98.6	5.84	0.085
	7	578	197.1	145.9	Tang.	ESP	Buell	267	158	830,000	-	98.2	98.2	5.9	0.099
Lansing Smith	1	150	56.4	52.6	Tang.	2-ESPs hot/cold	Buell/ Am. Std.	258	284	853×10^3 460×10^3	-	99.1	99.7	4.7 5.68	0.043
	2	190	71.3	64.8	Tang.	2-ESPs hot/cold	Buell/ Am. Std.	268	126	1.1×10^6 540×10^3	-	99.1	-	4.7 6.25	-
Scholz	1	49	19.6	16.79	Front	ESP	Buell	300	574	190,600	-	99.5	99.8	1.86	0.019
	2	49	19.6	16.79	Front	ESP	Buell	300	574	190,600	-	99.5	99.3	1.86	0.075
PENNSYLVANIA POWER AND LIGHT, ALLENTOWN, PENNSYLVANIA[c]															
Holtwood	17	79	-	45	Front	Baghouse	WF	325	2.42/1	200,000	234,800	0.017 gr/acf	99.93	-	0.042
Sunbury	1A, 1B, 2A, 2B	44	-	20.5	Front	Baghouse	WP	325	2.048/1	222,000	219,000	-	99.94	-	0.041
	3	880	-	45	Front	ESP	Buell	300	292	415,000	405- 415,000	99.5	99- 99.4	2.8 2.6	0.087
	4	140	-	55	Front	ESP	Buell	315	299	600,000	550- 612,000	99.5	97	3.5 2.8	0.26

(continued)

TABLE 65 (continued)

Station	Boiler No.	Size MW	Boiler data: Fuel consumption tons/hr: Design	Fuel consumption tons/hr: Average	Firing method	Control equipment data: Primary	Manuf.	Outlet Temp. °F	Critical[a] parameter	Flow rate, acfm: Design	Flow rate, acfm: Test	Overall efficiency, percent: Design	Overall efficiency, percent: Test	Velocity, ft/sec	Particulate emission rate lb/10^6 Btu
Brunner Island	1	350	125	-	Tang.	2-ESPs	Buell/ RC	325	135	$1x10^6$	$1.1x10^6$	99.5	80-98	5-6	0.6-2.0
25 ppm SO_3 injection															
	2	390	-	150	Tang.	2-ESPs	Buell/ RC	300	287	$1.44x10^6$	$1.3x10^6$	99.5	99	3.75	0.086
Montour	1&2	750 ea	250 ea	-	Tang.	ESP	Joy	290	175	$2.26x10^6$	$2.5x10^6$	99.5	90-99.3	4.5-5.5	0.05-0.9
PUBLIC SERVICE CO. OF COLORADO, DENVER, COLORADO[d]															
Valmont	5	166	75	60	Tang.	ESP/WS	RC/UOP	270	SCA = 89	746,000		87		7.5	
								250	L/G = 58	463,000 @ 250°F	350,000 @ 250°F		97	9.2-12.5	0.04
Comanche	2	350	217	185	Front and back	ESP	RC	650	307	$2.64.10^6$ @ 690°F	$1.63x10^6$ @ 295°F	-	98	5.2	0.04
Cherokee	4	350	150	140	Tang.	ESP/WS	RC/UOP	150	SCA = 135 L/G = 55	$1.52x10^6$ @ 275°F	$1.182x10^6$ @ 180°F	-	99.6	9.2-12.5	0.04
Arapahoe (SO_3 injection)	1	44	30	25	Top	ESP	E	295	279	$3.2x10^5$ @ 360°F	$2.75x10^5$ @ 295°F	99.2	99.7	2.75	0.028
SALT RIVER PROJECT WATER & POWER DISTRICT, PHOENIX, ARIZONA															
Navajo	1	750	326	279	Tang.	ESP	Joy	662	307	$3.94x10^6$	$4.3x10^6$	99.5	99.5	5.22 D 5.69 A	0.0504
	2	750	326	280	Tang.	ESP	Joy	662	307	$3.94x10^6$	$4.3x10^6$	99.5	-	5.22 D 5.69 A	0.071
	3	750	326	286	Tang.	ESP	Joy	662	307	$3.94x10^6$	$4.3x10^6$	99.5	-	5.22 D 5.69 A	0.0471
Hayden	2	268	131	130	Tang.	ESP	WF	685	339	$1.684x10^6$	$1.619x10^6$	99.6	99.1	5.16	0.1-0.11
TAMPA ELECTRIC CO., TAMPA, FLORIDA															
F. J. Gannon	6	414	151.4	98.14	Opposed	ESP	RC	293	327	$1.35x10^6$	$1.35x10^6$	99.8	99.84	4.9	0.029 gr/scf
	5	239	93.4	71.2	Opposed	ESP	RC	293	311	820,000	820,000	99.78	-	5.14	0.029 gr/scf

(continued)

TABLE 65 (continued)

Station	Boiler data					Control equipment data									Particulate emission rate lb/10^6 Btu
	Boiler No.	Size MW	Fuel consumption, tons/hr		Firing method	Primary	Manuf.	Outlet Temp. °F	Critical[a] parameter	Flow rate, acfm		Overall efficiency, percent		Velocity, ft/sec	
			Design	Average						Design	Test	Design	Test		
TENNESSEE VALLEY AUTHORITY, CHATTANOOGA, TENNESSEE															
Allen	1	330	102	96	-	ESP	LC	293	253.4	1.265×10^6	1×10^6	99	98.1	4.73	0.05
Colbert	2	200	81	71	PCFR	ESP	LC	352	196	906,000	810,000	97	99.4	5.1	0.06
	3	223	81	72	PCFR	ESP	LC	360	199	906,000	797,000	97	99.0	5.0	0.096
	4	223	81	65	PCFR	ESP	LC	351	203	906,000	780,000	97	99.1	4.9	0.088
	5	550	213.5	162	PCOP	ESP	CE	289	387	2×10^6	1.69×10^6	99.5	99.2	3.9	0.08
Cumberland	1	1300	540	502	PCOP	ESP	Am. Std.	290	170.3	4.7×10^6	-	99	99.1	5.86	0.12
	2	1300	540	486	PCOP	ESP	Am. Std.	290	170.3	4.7×10^6	-	99	99.06	5.86	0.12
John Sevier	1	223	83	75	PCTA	ESP	LC	295	487	920,000	647,000	98.5	99.0	3.36	0.031
	2	223	83	75	PCTA	ESP	LC	309	453	920,000	696,000	98.5	99.3	3.61	0.021
	3	200	83	77	PCTA	ESP	LC	293	488	920,000	645,000	98.5	99.1	3.35	0.0263
	4	200	83	75	PCTA	ESP	LC	301	477	920,000	660,000	98.5	99.4	3.43	0.0088
Johnsonville	1	125	59	48	PCTA	ESP	AAF	349	276	478,000	461,000	99.2	99.4	4.9	0.04
	2	125	59	41	PCTA	ESP	AAF	296	264	478,000	481,000	99.2	99.8	5.1	0.01
	3	125	59	50	PCTA	ESP	AAF	329	264	478,000	482,000	99.2	99.7	5.1	0.03
	4	125	59	49	PCTA	ESP	AAF	329	246	478,000	516,000	99.2	99.7	5.4	0.03
	5	147	59	54	PCTA	ESP	AAF	310	282	478,000	451,000	99.2	99.7	4.8	0.03
	6	147	59	51	PCTA	ESP	AAF	338	269	478,000	472,000	99.2	99.5	5.0	0.03
	7	173	62	55	PCFR	ESP	LC	294	220	525,000	505,000	98.5	96.9	5.5	0.18
	8	173	62	52	PCFR	ESP	LC	293	204	525,000	543,000	98.5	98.7	5.9	0.06
	9	173	62	52	PCFR	ESP	LC	306	201	525,000	553,000	98.5	98.3	6.0	0.05
	10	173	62	52	PCFR	ESP	LC	283	202	525,000	550,000	98.5	96.7	6.0	0.07
Kingston	1	175	63	50	PCTA	2 ESPs	AAF	325	476	500,000	-	99.2	-	4.2	-
	2	175	63	51	PCTA	2 ESPs	AAF	307	438	500,000	544,000	99.2	-	4.5	0.027
	3	175	63	50	PCTA	2 ESPs	AAF	310	439.5	500,000	542,000	99.2	-	4.5	0.019
	4	175	63	50	PCTA	2 ESPs	AAF	325	476	500,000	-	99.2	-	4.2	-
	5	200	83	77	PCTA	2 ESPs	AAF	340	439	700,000	723,000	99.2	-	4.5	0.012
	6	200	83	75	PCTA	2 ESPs	AAF	313	489	700,000	650,000	99.2	-	4.0	0.017
	7	200	83	78	PCTA	2 ESPs	AAF	325	418	700,000	760,000	99.2	-	4.7	0.015
	8	200	83	78	PCTA	2 ESPs	AAF	313	445	700,000	714,000	99.2	-	4.4	0.012
	9	200	83	77	PCTA	2 ESPs	AAF	287	512	700,000	620,000	99.2	-	3.9	0.01

(continued)

TABLE 65 (continued)

Station	Boiler data					Control equipment data									Particulate emission rate $lb/10^6$ Btu
	Boiler No.	Size MW	Fuel consumption, tons/hr		Firing method	Primary	Manuf.	Outlet Temp. °F	Critical[a] parameter	Flow rate, acfm		Overall efficiency, percent		Velocity, ft/sec	
			Design	Average						Design	Test	Design	Test		
VIRGINIA ELECTRIC & POWER CO., RICHMOND, VIRGINIA															
Bremo	3	69	30	21.43	Front	ESP	Joy	630	274	617,300	501,600	99.38	99.75	-	0.022
	4	185	55.8	55.89	Front	ESP	Joy	612	287	980,000	662,700	99.38	99.7	-	0.022
Chesterfield	6	693.9	233	171.5	Tang.	ESP	RC	-	176	$1.93x10^6$	-	99.5	-	6	0.04
Mount Storm	1	570.24	215	199.97	Tang.	ESP	RC	255	350	$2x10^6$	1,949,544	99.83	99.75	4.75-6.28	0.025
	2	570.24	215	208.7	Tang.	ESP	RC	275	350	$2x10^6$	1,822,200	99.83	99.7	4.75-6.28	0.045
	3	522	214	188.9	Tang.	ESP	RC	-	108	2,230,000	-	99.2	-	≤ 6	0.113

[a]ESP - SCA = ft^2/1000 acfm
Scrubber - L/G = gal/1000 ft^3
Baghouse - A/C = acfm/ft^2 cloth

[b]Duke Power Co. -
Allen units 1&2 and Marshall units 1&2: ESPs preceded by mech. coll.
Marshall unit 2: experimenting with Apollo additives

[c]Pennsylvania Power and Light -
Holtwood: baghouse installed in parallel with Chemico venturi scrubber
Sunbury 1&2: mech. coll. ahead of baghouse
Sunbury 3&4: new ESPs in parallel with existing ESP/mech. coll. (RC)
Brunner Is. 1&2: ESPs in parallel

[d]Public Service of Colorado -
Valmont: parallel arrangement

[e]Tennessee Valley Authority -
All ESPs at TVA (except for those at Allen, Colbert, and Cumberland stations) are installed in series with mech. coll.

Notes: To convert tons/hr to kg/sec, multiply by 1.8
To convert from °F to °C: °C = 5/9 (°F - 32)
To convert acfm to am^3/min, multiply by 2.8317 x 10^{-2}
To convert ft/sec to cm/sec, multiply by 30.48
To convert $lb/10^6$ Btu to ng/J, multiply by 430

TABLE 66. COAL ANALYSES FOR SOURCES LISTED IN TABLE 65

Company/station	Average heating value, Btu/lb*	Sulfur, percent	Ash, percent	Volatiles, percent	Water, percent
TVA					
Allen No. 1	11,180	3.3	11.4	35.7	11.0
Colbert No. 2	11,430	3.9	15.4	34.6	6.5
No. 3	11,470	4.0	15.5	34.8	6.2
No. 4	11,180	3.9	15.6	34.7	6.4
No. 5	11,420	4.0	15.4	34.9	6.3
Cumberland No. 1	10,530	3.8	17.2	33.2	9.3
No. 2	10,480	3.8	17.2	33.0	9.7
John Sevier No. 1	11,540	2.1	14.3	33.0	7.0
No. 2	11,470	2.2	14.6	33.2	7.1
No. 3	11,520	2.2	14.2	33.1	7.1
No. 4	11,520	2.2	14.2	33.3	7.1
Johnsonville No. 1	10,770	3.2	15.3	32.9	9.8
No. 2	10,760	3.1	15.4	33.0	9.7
No. 3	10,750	3.1	15.5	33.0	9.8
No. 4	-	3.1	15.6	33.3	9.6
No. 5	10,730	3.1	15.2	33.6	9.9
No. 6	-	3.1	15.3	33.1	9.6
No. 7	10,790	3.1	15.3	33.2	9.7
No. 8	10,780	3.1	15.4	33.3	9.6
No. 9	10,770	3.1	15.3	33.2	9.7
No. 10	10,760	3.1	15.4	33.1	9.7
Kingston No. 1	11,540	2.3	16.6	31.6	5.2
No. 2	11,580	2.2	16.4	32.0	5.4
No. 3	11,580	2.2	16.4	32.0	5.4
No. 4	-	2.3	16.5	31.8	5.5
No. 5	11,480	2.2	16.7	31.4	5.5
No. 6	11,480	2.2	16.7	31.8	5.5
No. 7	11,490	2.3	16.5	31.5	5.7
No. 8	11,550	2.3	16.4	31.8	5.5
No. 9	11,560	2.3	16.5	31.9	5.3
PP&L					
Holtwood	8,000	0.7	20-35		12-18
Sunbury No. 1&2	9,971	1.9	23.2		13.3
No. 3&4	12,250	1.8-2.5	11-15		6-9
Brunner Isl. No. 1	11,000-13,000	1.0-3.0	10-25		3-8
No. 2	11,000-13,000	1.0-3.0	10-25		3-8
Montour No. 1&2	11,000-12,500	1.0-2.5	12-25		3-8

(continued)

TABLE 66 (continued)

Company/station	Average heating value, Btu/lb*	Sulfur, percent	Ash, percent	Volatiles, percent	Water, percent
Duke Power Co.					
Allen	11,964	1.0	13.91		6.53
Belews Creek	11,839	1.02	13.25		6.42
Buck	11,766	1.02	14.35		7.17
Cliffside	11,985	1.28	14.61	30.0	6.54
Dan River	11,821	0.98	14.77		6.38
Lee	11,706	1.23	13.99		7.48
Marshall	11,722	1.06	14.54	32.0	7.37
Riverbend	11,633	1.17	14.26	30.0	7.47
VEPCO					
Bremo	12,390	0.775	8.83		7.61
Chesterfield	12,480	0.96	8.98		6.32
Mt. Storm	11,308	1.72	18.04		6.72
Salt River Project					
Navajo No. 1,2,&3	10,674	0.47	10.51	36.88	11.9
Hayden No. 2	10,333	0.46	11.52	33.74	12.23
Cleveland Electric Illum. Co.					
Eastlake No. 5	11,595	3.49	13.49	33-45	7.18
American Elect. Power					
Amos No. 3	11,614	0.92	15.0	30.0	6.8
Big Sandy No. 1	11,300	1.13	13.18		9.1
No. 2	11,506	1.14	13.6		7.4
Clinch R. No. 1,2,&3	11,900	0.76	15.9		6.1
Gavin No. 1&2	10,100	2.62	15.7		6.1
Glen Lyn No. 5&6	12,100	0.96	15.7		5.3
Kanawha R. No. 1&2	11,500	0.79	16.4		6.2
Tanners Creek No. 1&2	11,200	2.17	14.3		9.1
Consumer Power Co.					
Karn No. 1&2	11,431	2.76	12.03	33-40	8.64
J.R. Whiting No. 1,2&3	12,846	0.74	7.92	33-37	5.94
Campbell No. 1&2	11,116	2.92	15.47	36-40	7.38
Campbell No. 3	Designed for low sulfur Eastern coal				
Gulf Power Co.					
Crist No. 4,5,6&7	11,970	3.2	10.5	35.0	7.5
Scholz No. 1&2	12,233	2.7	13.5	35.0	5.2
Lansing-Smith No. 1&2	11,595	1.1	12.4	26.0	7.7

(continued)

TABLE 66 (continued)

Company/station	Average heating value, Btu/lb*	Sulfur, percent	Ash, percent	Volatiles, percent	Water, percent
Tampa Electric Co.					
F.J. Gannon No. 5&6	12,500	1.3	8.0	35.0	8.0
Public Service Co. of Colorado					
Arapahoe No. 1	10,700-11,400	0.35-0.55	8-12	30-34	7-11
Valmont No. 5	10,300-11,000	0.5-0.8	6-11	30-35	10-15
Comanche No. 2	7,900-8,700	0.25-0.45	4-6	30-32	26-30
Cherokee No. 4	10,700-11,400	0.35-0.55	8-12	30-34	7-11

*To convert Btu/lb to kJ/kg, multiply by 2.326

results show the varying degrees of collector performance encountered with these fuels. By combining Tables 16 and 65, there are sufficient data to enable an improved appraisal of the capabilities of precipitators as particulate control devices for coal-fired boilers.

Tables 17 and 22 presented information on facilities burning subbituminous coals (lignites) that were controlled by ESP's and scrubbers, respectively.

Experience with ESPs used at power plants burning North Dakota lignites has been generally satisfactory. The reported ESP performance is attributed partly to differences in coal properties wherein lignite has higher moisture and soidum contents than most bituminous coals. The principal operating problems with the above boilers relate to removal difficulties of fly ash from hoppers caused by the caking tendencies of high sodium fly ash.[2] It was noted that for eight power stations (Table 17) providing complete emission data, only two plants indicated emissions less than 13 ng/J (0.03 lb/10^6 Btu) while six plants reported emissions less than 43 ng/J (0.1 lb/10^6 Btu).

Data presented for wet scrubber installations have shown nominal recoveries for particulate matter and incidental sulfur oxide removal. Solids emissions ranged from 32.25 to 172 ng/J (0.075 to 0.4 lb/10^6 Btu) with four out of seven systems emitting less than 43 ng/J (0.1 lb/10^6 Btu). Precipitation of calcium sulfate and resultant scale formation has plagued some installations requiring that these plants resort to dilution of recirculating liquor so as to remain below the saturation level. No additional data on the boilers tested were available in the report.

Table 20 provided performance data for 12 tests on utility and industrial boilers controlled by fabric filters. EPA Method 5 was used to rate the filters on 7 of the systems. Information on the test method for the remaining five units was not available.

In table 23, performance data were shown for three utility boilers controlled by wet scrubbers. Further information on these units can be found in Tables 65 and 66.

Due to the paucity of emissions data for particulate control by wet scrubbers, a survey of the particulate removal capabilities of flue gas desulfurization (FGD) systems was undertaken; see Table 24. This information was obtained from a series of EPA reports and numerous follow-up telephone conversations with the source operators. Further data on the individual source test procedures are not available although EPA participation would most likely indicate that approved test methods were utilized.

Test data presented in Table 25 summarize emission rates from coal-fired boilers equipped with mechanical collectors. These test data were obtained by KVB, Inc. under a previous EPA study during which EPA test methods were used for all gaseous and particulate sampling. Only baseline (at least 80 percent of full load) test data were reported in Table 25. Although samples were analyzed for total and solid particulate material, only solid particulate emission levels were selected for listing in Table 25 to enable comparison with any test data obtained by EPA Method 5.

7.3 EMISSION SOURCE TEST DATA FOR OIL-FIRED BOILERS

In Table 26, test data for oil-fired boilers controlled by electrostatic precipitators were presented. This information, deriving from a previous GCA study, was based upon emissions compliance tests performed by GCA/Technology Division and stack test data provided by the Massachusetts Bureau of Air Quality Control.[3] Therefore, although not specified directly, all emissions data were based upon EPA Method 5 sampling since all data accepted and reported by the state agency must be obtained by appropriate EPA reference methods. Similarly, all GCA compliance testing is performed by EPA methods.

Table 27 indicated performance of a magnesium oxide scrubbing system previously installed at Boston Edison's Mystic Station - Boiler No. 6. (The scrubber has since been dismantled.) These data showed that particulate removals of 45 to 70 percent could be obtained even though the system had been designed solely for sulfur oxide removal. Since the rated capacity of boiler No. 6, Table 27, was approximately 160 MW_e, all tests were run with the boiler operating at greater than 90 percent load. It should be noted from Table 27 that the average inlet particulate loadings, 90.3 ng/J (0.21 $lb/10^6$ Btu) were at the high end of the range given previously in Table 12 for uncontrolled residual oil-fired boilers; 16.6 to 154.6 ng/J (0.0385 to 0.3596 $lb/10^6$ Btu). The higher levels are attributed to the use of the magnesium oxide additive. The outlet dust concentrations were also high, probably due to the low (1 kPa or 4 in. W.C.) pressure drop across the scrubber. An increase in the pressure drop would be expected to provide increased particulate removal. The above tests, which were performed for the Massachusetts state agency, utilized EPA sampling methods.

7.4 SUPPLEMENTAL TEST DATA

During the preparation of this document, additional test data have been obtained by subcontract* and from EPA's Office of Air Quality Planning and Standards (OAQPS). Table 67 presents source test data (controlled and uncontrolled) obtained from the Indiana, Maryland, Pennsylvania, and West Virginia state agencies and from a testing program conducted by the American

*Contract No. 1-614-029-222.

TABLE 67. SUPPLEMENTAL PARTICULATE EMISSIONS TEST DATA FOR CONTROLLED AND UNCONTROLLED FOSSIL FUEL BOILERS

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temp. ^oC (^oF)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1 ng/J (lb/10^6 Btu)	Test results: Run 2 ng/J (lb/10^6 Btu)	Test results: Run 3 ng/J (lb/10^6 Btu)	Test results: Average ng/J (lb/10^6 Btu)	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
Central State Hospital													
Indianapolis, IN	Erie City Boiler w/Laclede Traveling Grate Stoker												
1. (12/72)	23.4 (80)	None	2,538 (89,623)	254 (490)	22.3 (76)	EPA-5	606.3 (1.41)	235.6 (0.548)	198.7 (0.462)	348.3 (0.81)	2.96	11.1	25,728 (11,061)
2. (8/75)	Same unit	None	1,018 (35,953)	134 (274)	14.6 (50)	EPA-5	165.1 (0.384)	151.8 (0.353)	142.8 (0.332)	153.5 (0.357)	2.16	12.8	25,884 (11,128)
Richmond State Hospital													
Richmond, IN	Henry Vogt boiler w/Laclede Traveling Grate Stoker												
3. (8/75)	20.5 (70)	None	1,384 (48,887)	176 (349)	19 (65)	EPA-5	213.3 (0.496)	302.3 (0.703)	267.9 (0.623)	261 (0.607)	2.38	9.9	26,879 (11,556)

(continued)

TABLE 67 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temp. °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1 ng/J (lb/10^6 Btu)	Test results: Run 2 ng/J (lb/10^6 Btu)	Test results: Run 3 ng/J (lb/10^6 Btu)	Test results: Average ng/J (lb/10^6 Btu)	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
Muscatatuck State Hospital Muscatatuck, IN	Keeler Boiler w/Laclede Traveling Grate Stoker												
4. (8/75)	25.2 (86)	None	996 (35,180)	212 (413)	16.7 (57)	EPA-5	283.8 (0.66)	227.9 (0.53)	163.4 (0.38)	223.6 (0.52)	1.92	13.8	24,281 (10,439)
Madison State Hospital Madison, IN	Keeler Boiler w/Laclede Traveling Grate Stoker												
5. (8/75)	17.6 (60)	None	1,105 (39,013)	154 (309)	13.9 (47.5)	EPA-5	224.9 (0.523)	359.5 (0.837)	311.8 (0.725)	298.9 (0.695)	-	8.85	24,881 (10,697)
Evansville State Hospital Evansville, IN	Laclede Traveling Grate Stoker												
6. (8/75)	11.1 (38)	None	1,068 (37,733)	163 (325)	9.1 (31)	EPA-5	307.5 (0.715)	194.4 (0.452)	191.8 (0.446)	231.3 (0.538)	-	12.1	23.493 (10,100)

(continued)

TABLE 67 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temp. °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1 ng/J (lb/10^6 Btu)	Test results: Run 2 ng/J (lb/10^6 Btu)	Test results: Run 3 ng/J (lb/10^6 Btu)	Test results: Average ng/J (lb/10^6 Btu)	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
Norman Beatty Hospital Westville, IN (8/75) 7.	27.8 (95)	None	1,547 (54,617)	187 (368)	19.4 (66.3)	EPA-5	167.7 (0.39)	253.3 (0.589)	200.8 (0.467)	207.3 (0.482)	-	12.9	24,493 (10,530)
Logansport State Hospital Logansport, IN (9/75) 8.	B&W Boiler w/Laclede Traveling Grate Stoker 27 (92)	None	1,725 (60,933)	128 (263)	11.4 (39)	EPA-5	163.4 (0.38)	232.2 (0.54)	189.2 (0.44)	193.5 (0.45)	-	17.4	20,950 (9,007)
Lafayette Soldiers Home Lafayette, IN (9/75) 9.	Keeler Boiler w/Laclede Traveling Grate Stoker 12.9 (44)	None	530 (18,717)	134 (274)	7.3 (25)	EPA-5	107.5 (0.25)	202.1 (0.47)	154.8 (0.36)	154.8 (0.36)	-	10.9	24,311 (10,452)

(continued)

TABLE 67 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temp. °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1 ng/J (lb/10^6 Btu)	Test results: Run 2 ng/J (lb/10^6 Btu)	Test results: Run 3 ng/J (lb/10^6 Btu)	Test results: Average ng/J (lb/10^6 Btu)	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
Slippery Rock State College													
Slippery Rock, PA	B&W Boiler w/Single Retort Stoker												
10. (6/78)	9.7 (33)	None	591 (20,888)	194 (382)	5.9 (20)	EPA-5	304.9 (0.709)	-	-	-	1.3	11.0	31,401 (13,500)
Rockville State Correctional Inst.													
Rockview, PA	Keeler Boiler w/Multiple Retort Stoker												
11. (3/77)	12.9 (44)	None	-	-	9.1 (31)	EPA-5	-	-	-	382.7 (0.89)	1.35	10.35	32,015 (13,764)
Ashland State General Hospital													
Ashland, PA	Keeler Anthracite Boiler w/Single Retort Stoker												
12. (3/77)	3.5 (12)	None	-	-	2.1 (7)	EPA-5	-	-	-	94.6 (0.22)	0.57	12.6	29,405 (12,642)

(continued)

TABLE 67 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temp. °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1 ng/J (lb/10^6 Btu)	Test results: Run 2 ng/J (lb/10^6 Btu)	Test results: Run 3 ng/J (lb/10^6 Btu)	Test results: Average ng/J (lb/10^6 Btu)	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
Holidaysburg Veterans Home													
Holidaysburg, PA	Keeler CP Boiler w/multiple Retort Stoker												
(1/78) 13.	12 (41)	None	-	-	8.2 (28)	EPA-5	-	-	-	219.3 (0.51)	0.88	13.0	29,905 (12,857)
Ebensburg State School & Hospital													
Ebensburg, PA	Keeler CP Boiler w/Detroit Vibragrate Stoker												
(3/77) 14.	11.7 (40)	None	-	-	6.2 (21)	EPA-5	-	-	-	154.8 (0.36)	1.76	13.7	30,122 (12,950)
PPG Industries													
Cumberland, MD	CE Boiler w/Traveling Grate Stoker												
(5/72) 15.	13.2 (45)	None	-	-	5.9 (20)	EPA-5	103.2 (0.24)	103.2 (0.24)	98.9 (0.23)	101.9 (0.237)	1.0	12.0	27,912 (12,000)

(continued)

TABLE 67 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Control equipment	Flow rate m^3/min (acfm)	Temp. °C (°F)	Heat input MW (10^6 Btu/hr)	Test method	Run 1	Run 2	Run 3	Average	Sulfur %	Ash %	Heat content kJ/kg (Btu/lb)
		Test conditions					Test results ng/J (lb/10^6 Btu)				Fuel analysis		
Greenbrier Hotel													
White Sulphur Springs, W.Va.	Detroit Multiple-Retort Stoker												
16. (9/76)	16.4 (56)	None	853 (30,139)	228 (442)	14.7 (50)	EPA-5	364.2 (0.847)	122.6 (0.285)	211.6 (0.492)	232.6 (0.541)	0.88	3.1	33,143 (14,249)
Indiana State Prison													
Michigan City, IN	Keeler Boiler w/Laclede Traveling Grate Stoker												
17. (8/75)	10.8 (37)	MC	-	282 (539)	7.9 (27)	EPA-5	645 (1.5)	731 (1.7)	1075 (2.5)	817 (1.9)	-	13.6	22,290 (9,583)
18. (10/75)	Same	MC	454 (16,043)	226 (438)	7.6 (26)	EPA-5	150.5 (0.35)	137.6 (0.32)	137.6 (0.32)	141.9 (0.33)	2.56	7.7	22,483 (9,666)
State Correctional Institution													
Huntingdon, PA	Keeler CP Boiler w/Detroit Multiple Retort Stoker												
19. (4/78)		MC	606 (21,400)	287 (549)			-	-	-	196.1 (0.456)	3.0	13.0	30,703 (13,200)

(continued)

TABLE 67 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temp. °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1	Test results: Run 2	Test results: Run 3	Test results: Average	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
							← ng/J ($lb/10^6$ Btu) →						
Indiana University of Pennsylvania													
Indiana, PA	Union Boiler w/Detroit Vibragrate Stoker												
20. (6/78)	8.8 (30)	MC	379 (13,395)	250 (482)	5.6 (19)	EPA-5	-	-	-	220.2 (0.512)	1.4	13.0	30,703 (13,200)
State Correctional Institution													
Pittsburgh, PA	Keeler Boiler w/Traveling Grate Stoker												
21. (7/78)	7.9 (27)	MC	397 (14,021)	263 (505)	5.6 (19)	EPA-5	-	-	-	185.3 (0.431)	1.6	8.5	31,634 (13,600)
ABMA Program Test Site C													
	B&W Boiler w/Detroit Roto-grate Stoker												
22. (4/78)	73 (249)	MC	-	-	-	EPA-5	Boiler outlet	2589-15,661 (6.02-36.42)					19,745-28,517
23.							MC outlet	153.1-461 (0.356-1.072)			0.7-2.9	9.0-11.2	(8,490-12,260)

(continued)

TABLE 67 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temp. °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1	Test results: Run 2	Test results: Run 3	Test results: Average	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
							ng/J ← ($lb/10^6$ Btu) →						
ABMA Program (Cont'd)													
Test Site D													
24. (7/78) 25.	B&W Boiler w/Detroit Vibragrate Stoker 26.4 (90)	MC	-	-	-	EPA-5	Boiler outlet 302.7 - 477.3 (0.704 - 1.11) MC outlet - 139.8 - 326.8 (0.325 - 0.76)				0.8-2.65	6.85-8.0	29,773-31,634) (12,800-13,600)
Test Site E													
(11/78) 26.	Riley Boiler w/Spreader Stoker	MC	-	-	-	EPA-5	1299 (3.02)	2180 (5.07)	2713 (6.31)	2064 (4.8)			
27.	52.8 (180)						137.2 (0.319)	91.6 (0.213)	114.4 (0.266)	114.4 (0.266)	1.0	4.48	32,120 (13,809)
Monsanto Co.													
Nitro, W.Va. (7/75) 28.	Spreader Stoker 44 (150)	MC & ESP in series	-	-	44 (150)	EPA-5	5.2 (0.012)	4.3 (0.01)	3.4 (0.008)	4.3 (0.01)	0.57	11.4	26,468 (11,379)

(continued)

TABLE 67 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions					Test results				Fuel analysis		
		Control equipment	Flow rate m^3/min (acfm)	Temp. °C (°F)	Heat input MW (10^6 Btu/hr)	Test method	Run 1	Run 2	Run 3	Average	Sulfur %	Ash %	Heat content kJ/kg (Btu/lb)
							ng/J ($lb/10^6$ Btu)						
ABMA Program Test Site B	Riley Boiler w/Spreader Stoker	MC & ESP in Series											
29. (11/77)	75 (257)		-	-	-	EPA-5	4876 (11.34 - Average of 22 Readings)				0.85	8.0	30,761 (13,225)
30.							248.5 (0.578 - Average of 18 Readings)				0.85	8.0	30,761 (13,225)
31.							8.6 (0.02 - Average of 2 Readings)				0.85	8.0	30,761 (13,225)
Joseph E Seagram's & Sons, Inc.													
Baltimore, MD	B&W Boiler	MC & ESP in Series											
32. (3/77)	22 (75)		-	-	22 (75)	EPA-5	60.2 (0.14)	34.4 (0.08)	50.3 (0.117)	48.2 (0.112)	-	9.3	28,145 (12,100)
ABMA Program Test Site A													
33.	Foster-Wheeler Boiler w/De-troit Spreader Stoker	MC, ESP & SO_2 Scrubber in Series					6201 (14.42 - Average of 13 tests)				0.5	5.7	24,531 (10,469)
34. (8/77)	98 (333)		-	-	64.5 (220)	EPA-5	275.2 (0.64 - Average of 8 tests)				0.93	6.1	24,532 (10,547)
35.					64.8 (221)	EPA-5	7.1 (0.0166)	8.3 (0.0194)	24.8 (0.0576)	13.4 (0.0312)	0.65	5/8	24,411 (10,495)

(continued)

TABLE 67 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temp. °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1 ng/J (lb/10^6 Btu)	Test results: Run 2 ng/J (lb/10^6 Btu)	Test results: Run 3 ng/J (lb/10^6 Btu)	Test results: Average ng/J (lb/10^6 Btu)	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
<u>ABMA Program</u> (Cont'd)													
<u>Test Site A</u>													
(8/77) 36.					53 (181)	EPA-5	5.5 (0.0128)	-	-	-	0.78	4.8	24,258 (10,429)
<u>Test Site X</u>													
(11/77) 37.	Kewanee Boiler w/Canton Under-feed Stoker 1.5 (5)	FF	-	-	1.5 (5)	EPA-5	533.2 (1.24)	455.8 (1.06)	339.7 (0.79)	442.9 (1.03)	0.6	6.3	26,991 (11,604)

Notes:

1. Sampling in breeching
2. Sampling in stack
3. Sampling in stack
4. Sampling in stack
5. Sampling in stack
6. Ash buildup the cause of high results in Run 1
11. Sampling in breeching
12. Sampling in breeching
13. Sampling in breeching
14. Sampling in breeching
15. Sampling in stack
16. Sampling breeching
17. Collector <u>not</u> operating
18. Collector operating
20. Collector outlet
21. Collector outlet
22. Collector inlet
23. Collector outlet
24. Collector inlet
25. Collector outlet
26. Collector inlet
27. Collector outlet
28. Sampling in stack
29. Boiler outlet
30. MC outlet
31. Downstream of ESP & MC
32. Sampling in stack
33. Boiler outlet
34. MC outlet
35. ESP outlet
36. Sampling in stack
37. Collector inlet

Boiler Manufacturers' Association (ABMA). Data given for uncontrolled boilers or collector inlet tests can be used to supplement the uncontrolled data presented previously in Table 12. Data for controlled boilers are mainly for mechanical collectors and indicate the difficulty in achieving emissions less than the moderate level with this type of control.

Worthy of note is test number 28, which shows the performance for a mechanical collector and electrostatic precipitator in series installed on a spreader stoker boiler. The test results showed an average outlet emission rate of 4.3 ng/J (0.01 lb/10^6 Btu). Other results (Tests 31 and 32) for the same collector arrangement show average emission rates of 8.6 ng/J (0.02 lb/10^6 Btu) and 48.2 ng/J (0.112 lb/10^6 Btu), respectively.

Emission source test data obtained from OAQPS is presented in Table 68. These data show a variety of collector combinations and emission results.

Comments concerning all tests in each of these tables are indicated at the end of each table and are identified by the test code number.

TABLE 68. SUPPLEMENTAL PARTICULATE EMISSIONS TEST DATA FOR CONTROLLED FOSSIL FUEL BOILERS

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Flow rate m^3/min (acfm)	Temperature °C (°F)	Heat input MW (10^6 Btu/hr)	Test method	Test results: Run 1 ng/J (lb/10^6 Btu)	Run 2	Run 3	Average	Fuel analysis: Sulfur %	Ash %	Heat content kJ/kg (Btu/lb)
<u>E.I. DuPont</u>													
Parkersburg, W.Va. Washington Works	4-Spreader stokers	4-Units equipped with multi-cyclones followed by fabric filters											
1. (3/76)	18.7 (64)		-	163 (325)	19-20 (64-67)	EPA-5	8.0 (0.0187)	6.5 (0.0151)	3.9 (0.009)	6.1 (0.0143)	2.8	7.0	31,365 (13,500)
2. (3/76)	36.6 (125)			160 (320)	35-36 (121-122)	EPA-5	4.3 (0.01)	3.4 (0.008)	2.3 (0.0053)	3.4 (0.0078)	3.0	7.0	32,295 (13,900)
3. (11/75)	53 (181)		-	188 (370)	59-60 (200-205)	EPA-5	49.9 (0.116)	14.2 (0.033)	6.5 (0.015)	23.7 (0.055)	3.0	6.9	32,295 (13,900)
4. (12/75)	70.6 (241)		-	182 (360)	76-78 (261-266)	EPA-5	27.5 (0.064)	7.0 (0.0163)	17.1 (0.0398)	17.2 (0.04)	3.0	7.7	32,062 (13,800)

(continued)

TABLE 68 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temperature °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1	Test results: Run 2	Test results: Run 3	Test results: Average	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
							ng/J ($lb/10^6$ Btu)						
Duke University													
Durham, N.C. West Campus	2-Spreader stokers												
5. (7/75)	26.4 (90)	MC	770 (27,200)	110 (230)	10-13 (33-45)	EPA-5	5268 (12.25)	959 (2.23)	1871 (4.35)	2700 (6.28)	not available		
6. (7/75)	22 (75)	MC	623 (22,000)	157 (315)	6-11 (20-38)	EPA-5	417 (0.97)	464 (1.08)	598 (1.39)	495 (1.15)	not available		
7. (10/75)	Spreader Stoker	MC	750 (26,500)	166 (330)	16 (56)	EPA-5	396 (0.92)	783 (1.82)	-	589 (1.37)	not available		
8. (10/75)		MC	1,206 (42,600)	121 (250)	20 (69)	EPA-5	9,297 (21.62) omit	748 (1.74)	254 (0.59)	501 (1.165)	not available		
9. (4/76)		MC	1,356 (47,900)	123 (253)	26 (90)	EPA-5	77.4 (0.18)	137.6 (0.32)	90.3 (0.21)	103.2 (0.24)	not available		
J. P. Stevens & Co.													
Roanoke Rapids, N.C. Rosemarie Plant No. 1													
10. (4/74)	Erie City Boiler	-	484 (17,100)	150 (302)	-	EPA-5	214.6 (0.499)	241.2 (0.561)	-	228 (0.53)	not available		

(continued)

TABLE 68 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Control equipment	Test conditions				Test results				Fuel analysis		
			Flow rate m^3/min (acfm)	Temperature °C (°F)	Heat input MW (10^6 Btu/hr)	Test method	Run 1	Run 2	Run 3	Average	Sulfur %	Ash %	Heat content kJ/kg (Btu/lb)
							ng/J (lb/10^6 Btu)						
The Great Western Sugar Co.													
Denver, Colo.	Coal-fired boiler	Koch Venturi scrubber											
11. (12/74)			1,543 (54,500)	47 (116)	39 (134)	EPA-5	28 (0.065)	28 (0.065)	-	28 (0.065)	-	10.54	23,373 (10,060)
12.			1,410 (49,800)	41 (106)	40 (138)	EPA-5	-	-	-	40 (0.093)	-	8.52	29,927 (12,881)
13. (10/75)			3,228 (114,000)	49 (120)	54 (185)	EPA-5	45.6 (0.106)	46 (0.107)	80.4 (0.187)	57.3 (0.133)	-	-	23,215 (9,992)
Caterpillar Tractor Co.													
Mossville, Illinois	2-Detroit spreader stokers	FGD scrubber											
14. (1-2/77)	23 (80)		-	76 (169)	23 (80)	EPA-5	55.5 (0.129)	42 (0.0977)	37.1 (0.0862)	44.8 (0.1043)	3.0	9.23	23,419 (10,080)
15.	44 (150)	FGD scrubber	-	92 (197)	31 (105)	EPA-5	67.6 (0.1572)	69.7 (0.1622)	86 (0.1999)	74.4 (0.1731)	2.9	8.95	22,536 (9,700)

(continued)

TABLE 68 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temperature °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results ng/J (lb/10^6 Btu): Run 1	Test results: Run 2	Test results: Run 3	Test results: Average	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
Mossville, Illinois (Cont'd) 16.	44 (150)	FGD scrubber	-	85 (185)	44 (150)	EPA-5	38.3 (0.089)	46.1 (0.1073)	47.5 (0.1105)	44 (0.1023)	2.88	8.28	22,827 (9.825)
Jolliet, Illinois (4/77)	2-Spreader stokers	Both have mechanical collectors plus wet scrubbers											
17.	23 (80)		-	52 (125)	21 (70)	EPA-5	58.1 (0.135)	93.3 (0.231)	88.6 (0.206)	82.1 (0.191)	2.8	12.0	29,042 (12,500)
18.	29 (100)		-	54 (130)	26 (90)	EPA-5	120 (0.279)	86.9 (0.202)	-	103.6 (0.241)	2.8	12.5	29,623 (12,750)
Mossville, Illinois 19.	Detroit spreader stoker	FGD scrubber (Venturi)	-	209 (409)	23 (80)	EPA-5	2679 (6.23)	2967 (6.90)	2980 (6.93)	2877 (6.69)	2.86	8.8	23,524 (10,125)
20. (10/76)	23 (80)	↓	-	70 (158)	23 (80)	EPA-5	50.4 (0.1173)	37.3 (0.0868)	62.5 (0.1453)	50.1 (0.1165)	2.86	8.8	23,524 (10,125)
21.			-	198 (388)	16 (56)	EPA-5	2404 (5.59)	2434 (5.66)	2709 (6.30)	2516 (5.85)	2.9	8.3	23,187 (9,980)
22.			-	77 (171)	16 (56)	EPA-5	58.1 (0.135)	56.8 (0.132)	63.2 (0.147)	59.3 (0.138)	2.9	8.3	23,187 (9,980)
23.			-	179 (354)	8 (28)	EPA-5	2176 (5.06)	2137 (4.97)	1621 (3.77)	1978 (4.60)	2.8	9.6	23,426 (10,083)
24.			-	88 (191)	8 (28)	EPA-5	53.8 (0.125)	42.3 (0.0984)	60.7 (0.1411)	52.2 (0.1215)	2.8	9.6	23.426 (10,083)

(continued)

TABLE 68 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temperature °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1, ng/J (lb/10^6 Btu)	Test results: Run 2, ng/J (lb/10^6 Btu)	Test results: Run 3, ng/J (lb/10^6 Btu)	Test results: Average, ng/J (lb/10^6 Btu)	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
Decatur, Illinois													
25. (4/77)*		Fabric filter	960 (33,900)	165 (329)	-	EPA-5	18.1 (0.042)	28.4 (0.066)	9.9 (0.023)	18.9 (0.044)	2.0	11.7	29,685 (12,777)
26.			881 (31,100)	162 (324)	-	EPA-5	12.9 (0.03)	21.1 (0.049)	22.8 (0.053)	18.9 (0.044)	1.8	8.8	29,713 (12,789)
City Utilities of Springfield, Mo.													
Southwest Power Station	Pulverized coal	ESP & FGD scrubber											
27. (9/77)	512 (1747)		13,290 (469,333)	56 (132)	499 (1702)	EPA-5	8.6 (0.0201)	6.1 (0.0141)	9.0 (0.0209)	7.9 (0.0184)	3.56	14.1	29,634 (12,755)
28.	↓	ESP	18,487 (652,850)	135 (275)	499 (1702)	ASME No. 27	3006 (6.99)	3281 (7.63)	-	3143 (7.31)	3.56	14.1	29,634 (12,755)
29.	↓	ESP	19,131 (675,600)	154 (309)	499 (1702)	ASME No. 27	8.7 (0.0203)	7.1 (0.0165)	-	7.9 (0.0184)	3.56	14.1	29,634 (12,755)
Tennessee Eastman Co.													
P.O. Box 511 Kingsport, TN	Stoker-fired												
30. (6/76)	63 (215)	ESP	2,222 (78,473)	152 (305)	42 (142)	EPA-5	43.9 (0.102)	40.8 (0.095)	21.1 (0.049)	35.3 (0.082)	0.94	9.1	30,064 (12,940)

(continued)

TABLE 68 (continued)

Facility, name, location and code No. (test date)	Boiler type and heat input capacity MW (10^6 Btu/hr)	Test conditions: Control equipment	Test conditions: Flow rate m^3/min (acfm)	Test conditions: Temperature °C (°F)	Test conditions: Heat input MW (10^6 Btu/hr)	Test conditions: Test method	Test results: Run 1 ng/J ($lb/10^6$ Btu)	Test results: Run 2 ng/J ($lb/10^6$ Btu)	Test results: Run 3 ng/J ($lb/10^6$ Btu)	Test results: Average ng/J ($lb/10^6$ Btu)	Fuel analysis: Sulfur %	Fuel analysis: Ash %	Fuel analysis: Heat content kJ/kg (Btu/lb)
Adolph Coors Co.													
Golden, CO	Pulverized coal												
31. (6/77)	73 (250)	Fabric filter	4,814 (170,000)	179 (355)	73 (250)	EPA-5 EPA-17	14.4 (0.0336)	13.6 (0.0316)	18.4 (0.0428)	15.5 (0.036)	0.53	10.2	25,650 (11,040)

*Test results given as -

metric units: mg/dsm^3 (English units): gr/dscf

Notes:

1. Boiler No. 2
2. Boiler No. 4
3. Boiler No. 5
4. Boiler No. 6
5. Boiler No. 2 - Old Stack - Fly Ash Reinjection - Grates cleaned between Runs 1 and 2
6. Boiler No. 3 - New Stack - Grates cleaned between Runs 1 and 2
7. Boiler No. 2 - Collector Inlet
8. Boiler No. 2 - Collector Outlet
9. Boiler No. 2 - Collector Outlet
10. Sampling in breeching
11. Hanna (Rosebud) coal
12. Lisbon coal
13. Runs 1 and 2 - ΔP = 1.24 kPa (5 in.W.C.) Run 3 - ΔP = 0.75 kPa (3 in. W.C.)
14. Boiler No. 1 - Avg. ΔP = 5 kPa (20 in.W.C.)
15. Boiler No. 4 - Avg. ΔP = 5.4 kPa (21.8 in.W.C.)
16. Boiler No. 4 - Avg. ΔP = 6.4 kPa (25.7 in.W.C.)
17. Boiler No. 2
18. Boiler No. 3
19. Scrubber Inlet - ΔP = 5.1 kPa (20.3 in.W.C.)
20. Scrubber Outlet
21. Scrubber Inlet - ΔP = 5 kPa (20 in.W.C.)
22. Scrubber Outlet - ΔP = 5 kPa (20 in.W.C.)
23. Scrubber Inlet - ΔP = 3.8 kPa (15.2 in.W.C.)
24. Scrubber Outlet - ΔP = 3.8 kPa (15.2 in.W.C.)
25. Pulse-jet cleaning
26. Reverse Air Cleaning
27. Downstream of both collectors
28. ESP inlet
29. ESP outlet
30. Boiler No. 21
31. Boiler No. 4 - In-stack plus out-of-stack

7.5 TEST METHODS

Most of the test data presented in Section 2.0 were developed under EPA contracts using approved EPA sampling methods; i.e., Methods 1 through 5 for particulate materials as originally published in the Federal Register - Thursday, December 23, 1971, Volume 36, No. 247 - "Standards of Performance for New Stationary Sources." These methods are listed as follows:

Method 1 - Sample and Velocity Traverses for Stationary Sources

Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)

Method 3 - Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight

Method 4 - Determination of Moisture in Stack Gases

Method 5 - Determination of Particulate Emissions from Stationary Sources.

Particulate sampling by these EPA reference methods requires that, if at all possible, the sampling site be located at least eight duct diameters downstream and two duct diameters upstream from any flow disturbance or perturbation. When these conditions are met, the minimum number of traverse points would be 12. However, deviations from these conditions are often encountered that usually require several additional sampling points. Additional sampling criteria are that the minimum sampling time be 1 to 2 hours and that the minimum sample volume be 0.85 m^3 (30 ft^3) per run when corrected to standard conditions on a dry basis. Appropriate meter readings, temperatures, pressures, and other relevant information are to be recorded every 5 minutes. Test results are deemed acceptable when sampling is carried out between 90 and 110 percent of isokinetic flow. Isokinetic sampling prevails when the average velocity of the gas sample entering the probe is equal to the local duct velocity.

Adherence to Methods 1 through 5 results in a stack test which is well documented, representative, and usually repeatable since the same procedures and analyses are used each time a test is performed. However, special precautions must be taken to guarantee complete recovery of any particulate material that deposits in the upstream section of the sampling train. It should also be recognized that the presence of high SO_x concentrations coupled with a condensing atmosphere can cause artificially high particulate accumulations on dry filter media because of added moisture.

Although the original Method 5 specified that the sampling filter located outside the duct be maintained at a minimum temperature of 121°C (250°F ± 25°F) a more recent EPA revision of August 1977 allows the collection temperature to range up to 160°C (320°F). This change allows the "in-stack" Method 17 particulate sampling method discussed in the 24 September 1976 Federal Register (41FR42020) to be used interchangeably with Method 5. It is specified that Method 17 is an acceptable procedure for sampling combustion effluents provided that the stack temperature does not exceed 160°C (320°F). The method is not considered acceptable for higher flue gas temperatures because of the possibility that certain combustion products that might condense as particulate material at 160°C (320°F) may penetrate the filter media.

A major advantage of Method 17 is that it eliminates the difficult and potentially error-producing probe washing step which is an integral part of Method 5. Method 17 actually evolves from a sampling technique described originally in the ASME Power Test Code No. 21 of 1941.[4] The above method was later modified at Harvard University by substituting high efficiency all-glass thimbles for the porous, rigid ceramic thimbles suggested by ASME. Use of the all-glass thimble was described by Dennis (1952)[5] et al., and more recently in a memorandum from Dennis submitted to the State of Massachusetts in August 1972.[6] The latter method was accepted in Massachusetts until the State adopted EPA Method 5 for standardization purposes in May 1975. The only major equipment differences between the Method 17 and the Harvard technique were that rugged and inexpensive Venturi-type flow meters were used in place of the delicate and very expensive dry meters used in the Methods 5 and 17 sampling trains. Additionally, a separate Pitot-static tube was used to establish local gas velocities at the sampling locations.

A current test method often used by source operators to determine particulate emissions is a revised version of the original Power Test Code of 1941; Power Test Code No. 27 (PTC-27) - "Determining the Dust Concentration in a Gas Stream" published by the American Society of Mechanical Engineers (ASME) in 1957.[7] The above method is very similar to EPA Methods 1 through 5 except that PTC-27 is not as detailed in its requirements and can be modified depending upon site-specific factors. In addition, the particulate filter contained within a sampling nozzle is usually inserted directly into the gas stream as opposed to the EPA Method 5 extraction approach in which the filter is located outside of the duct but maintained at a minimum temperature of 121^{o}C (250^{o}F ± 25^{o}F). Unless an upper limit in stack temperature; e.g., 160^{o}C (320^{o}F) is set for PTC-27, it can be argued that this method may fail to capture any vapor phase material that would condense at 160^{o}C (320^{o}F) or lower.

General test requirements and procedures followed in PTC-27 are listed below and compared to the EPA methods where appropriate:

- PTC-27 is designed for particles ≥ 1μ with coarse alundum thimbles for collection.
- Where the range of velocities does not exceed 2 to 1, from 12 to 20 points are recommended for large ducts (> 25 ft^2 in cross section) and from 8 to 12 points for small ducts.
- Where steep velocity gradients or extreme turbulence are encountered, the number of points may be doubled or trebled.

- The method of subdividing a duct into sampling points is the same as EPA Method 5.
- Operating conditions should be kept constant for 1 hour prior to the start of each run.
- Where steady state operation is not possible, the sampling rate should be adjusted so as to maintain a zero differential between static pressure within and outside of the sampling nozzle mouth when a null-type probe is used.
- Filters used should have a filtering efficiency of 99.0 percent by weight for the dust to be encountered during the test.
- When dust concentrations are very high, a moderate efficiency filter within the probe nozzle can be followed by a high efficiency filter located outside the duct (basically the EPA Method 5 system).
- At least two runs should be made at each basic flow rate within the stack. EPA Method 5 requires three runs.
- Samples should be operated for a minimum of 10 minutes at each point. EPA Method 5 requires a minimum of 2 minutes per point.
- Where steady conditions exist and a predetermined setting for velocity pressure has been computed for each point, a record of the computations shall be kept.
- Where the null method is used and sampling velocity is adjusted to the existing dust velocity, no record need be made of velocity pressure.
- Average gas pressure and temperature at the metering device for each sampling point shall be recorded during each test. Other indicating instruments shall be read every 15 minutes.

EPA Methods 5 and 17 and ASME PTC-27 are viable methods for particulate sampling where strict adherence to procedures is followed. EPA Method 5 requires more detailed operation and more recording of data than PTC-27, but there are situations where the ASME method would be the better choice. For example, a gas stream with a high grain loading might be better sampled with an in-stack moderate efficiency thimble and an external backup filter. The thimble would pick up coarser material and allow smaller-sized particles to pass through and be collected at the filter. Use of the EPA Method in this case might result in rapid plugging of the filter and an attendant reduction in flow. The necessary changes in flow rate to achieve isokinetic sampling would be difficult and would leave more room for sampling error. However, the EPA Method can be modified by including a cyclone in the sampling train which will collect coarse material and reduce the loading to the filter.

In summary, it can be said that the EPA Methods are suitable where all tests are to be performed on the same basis (for compliance purposes, for example) such that comparison of several tests would be possible. The ASME test methods may be preferable for unique source conditions and where the interest is only for the particular source sampled.

7.6 ACCURACY OF TEST METHODS AT LOWERED EMISSION LEVELS

Regardless of the type of testing procedure chosen for particulate sampling, the accuracy of the final result is a function not only of the test methods, but also the competence of the individuals performing the tests and the related final analyses and calculations.

The requirement of EPA Method 5 for isokinetic sampling between 90 to 110 percent of the stack velocity implies a minimal error in sampling of $\pm$ 1 percent for particle diameters less than 15 μm.[8] One must also consider potential inaccuracies in gravimetric analyses, equipment meter readings, and possible sample losses to arrive at the overall accuracy for the test results. Assuming that all associated equipment is properly maintained and calibrated, one could add another deviation of roughly $\pm$ 10 percent to give an overall accuracy of around ± 11 percent. Obviously, this could mean the difference between compliance and noncompliance in some cases.

There are other factors which should be considered as control levels are made more stringent. For a controlled steam generating unit operating near the 43 ng/J (0.1 lb/10^6 Btu) emission level, the amount of particulate collected in a train for a 0.85 Nm^3 (30 dscf) sample over a 1-hour period (for ideal conditions) would be about 80 mg, proportioned between the probe and the filter. The ratio of probe catch to filter catch ranges between 15/85 and 50/50 depending on the sampling velocity and particle size distribution. Another requirement for a valid test is that the minimum weight collected on the filter must be no less than 5 percent of the filter weight. Since a typical filter weighs 220 mg, the minimum allowable filter catch is 11 mg. Therefore all conditions for a valid test are clearly met by a 1-hour test for a dust loading corresponding to emissions of 43 ng/J (0.1 lb/10^6 Btu).

On the other hand a source emitting at the 4.3 ng/J (0.01 $lb/10^6$ Btu) level could, by a similar analysis require a 3-hour test period to collect sufficient material. A longer test may increase the chances for equipment and procedural errors or failures as well as increasing the cost of a stack test. These factors must be considered in the formulation of emission control levels.

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16. ABSTRACT The report assesses applicability of particulate control technology to industrial boilers. It is one of a series to aid in determining the technological basis for a New Source Performance Standard for Industrial Boilers. It gives current and potential capabilities of alternative particulate control techniques, and identifies the cost, energy, and environmental impacts of the most promising options. Fabric filters and electrostatic precipitators (ESPs) can exceed 99% control efficiency and can be used on industrial boilers. A baghouse seems more economical for very small combustion units or to meet a very stringent emissions requirement when burning low sulfur coal. An ESP might be more aptly applied to the largest industrial units, involving intermediate or moderate control levels for very small boilers and higher sulfur coals. Wet scrubbers are not expected to be used for particulate control alone, but might be used to control both SO2 and particulates in the case of modest particulate control levels. Mechanical collectors could be important for some cases. Control costs exert a significant impact as boiler size and control level decrease. For regulatory purposes, this assessment must be viewed as preliminary, pending results of the more extensive examinations of impacts called for under Section 111 of the Clean Air Act.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Filters	Pollution Control	13B	
Assessments	Electrostatic Precipitators	Stationary Sources	14B	
Dust		Particulate	11G	13I
Aerosols	Scrubbers	Industrial Boilers	07D	07A
Boilers		Fabric Filters	13A	
Flue Gases		Baghouses	21B	
Fabrics			11E	

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