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PARTICULATE AND SULFUR DIOXIDE EMISSION CONTROL COSTS FOR LARGE COAL-FIRED BOILERS

by

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EXECUTIVE SUMMARY

Introduction

In support of a program to review New Source Performance Standards (NSPS) for particulate and sulfur dioxide (SO_2) emissions from coal-fired steam generators, the U.S. Environmental Protection Agency (EPA) is preparing estimates of the costs of air pollution control equipment. The program includes estimating costs of the various control alternatives available to meet the present NSPS of 43 nanograms particulate per joule of heat input (0.1 lb/10^6 Btu) and 516 nanograms SO_2 per joule of heat input (1.2 lb/10^6 Btu), with comparative cost estimates of control options to meet alternative emission levels of 22 nanograms particulate per joule heat input (0.05 lb/10^6 Btu), 13 nanograms particulate per joule heat input (0.03 lb/10^6 Btu), 215 nanograms SO_2 per joule heat input (0.5 lb/10^6 Btu), and 90 percent reduction of potential SO_2 emissions. EPA has contracted with PEDCo Environmental, Inc. to develop cost estimates for flue gas desulfurization (FGD) systems, physical coal cleaning facilities, electrostatic precipitators (ESP), fabric filters, venturi scrubbers, cost differentials of boilers designed for western subbituminous coals versus Eastern coals, and costs of transporting coal from the west to eastern markets for each of the alternative emission levels. Model steam-electric generating plants of various sizes were used as a basis for estimating these costs.

Emission Control Alternatives to Meet Revised NSPS

The revisions to the NSPS for particulate emissions being considered in this study are 22 ng/J (0.05 $lb/10^6$ Btu) and 13 ng/J (0.03 $lb/10^6$ Btu). Control devices available to attain these emission levels are ESP's and fabric filters. Wet venturi scrubbers may be utilized to attain the present NSPS level of 43 ng/J (0.1 $lb/10^6$ Btu) particulate emission and the alternative level of 22 ng/J (0.05 $lb/10^6$ Btu) particulate emission.

The alternative NSPS levels being considered for SO_2 emissions are 215 ng/J (0.5 $lb/10^6$ Btu) and 90 percent control regardless of potential SO_2 emissions. Control techniques available to meet these alternative standards are FGD, combination physical coal cleaning and FGD, and low sulfur coal and FGD.

Control System Cost Components

The costs of a control system consist of the capital costs of purchasing and installing the system and the annual costs of ownership, operation and maintenance of the system.

Capital costs are further categorized as direct and indirect costs. Direct costs are those for purchase of the items of equipment and the labor and material required to install the equipment and interconnect it. Indirect costs are those not attributed to specific equipment items such as freight, interest, taxes, spare parts, engineering, overhead, shakedown, and contingencies. Annual costs are categorized as operation and maintenance costs and fixed costs. Operation and maintenance costs include those expenditures for raw materials, utilities, and maintenance and supervising labor. Fixed costs include depreciation, taxes, insurance, and costs of borrowed capital.

Cost Estimating Approach

The control system costs were determined based on a typical new coal-fired plant model. Three sizes were selected for analysis of particulate control system costs and five sizes for analysis of SO_2 control system costs. A midwest location is assumed for the model plants. For particulate control systems, three control levels were examined: 43 ng/J (0.1 lb/10^6 Btu), 22 ng/J (0.05 lb/10^6 Btu) and 13 ng/J (0.03 lb/10^6 Btu). For SO_2 control alternatives, three control levels were also analyzed: 516 ng/J (1.2 lb/10^6 Btu), 90 percent removal of SO_2 regardless of potential emission levels, and 215 ng/J (0.5 lb/10^6 Btu).

Table 1 presents a summary of the model plant characteristics and assumptions used for the cost analysis of particulate control options. Table 2 presents assumptions and characteristics used in the SO_2 control option analysis.

In the analysis several types of coal are considered including three Eastern coals, two Western coals, and an Eastern anthracite coal. Analyses of these coals are given in Table 3.

Parameters used for the particulate control systems cost estimates are given in Table 4. Parameters used for the FGD systems cost estimates are given in Table 5.

Computer programs developed by PEDCo were then used to calculate costs for each control alternative based on the model plant parameters. The computer program uses mid-1976 costs as a basis with an escalation rate of 7.5 percent per year through project completion. Results of the cost estimates are expressed in mid-1980 dollars.

Averaging Times

The average time period over which an emission regulation must be met has a significant impact on the design and applicability of various control techniques. Averaging times will have the most impact on SO_2 emission regulations. Factors affecting averaging times include the sulfur variability in fuel, the reliability of the pollution control

Table 1. MODEL PLANT PARAMETERS AND ASSUMPTIONS USED IN THE PARTICULATE CONTROL ANALYSIS

Model plant parameters	Characteristics and assumptions			
Plant capacities, MW	25, 100, 200, 500, and 1000 (single boilers)			
Plant status	New			
Coal characteristics	(See Table 3)			
Particulate control requirements	(1) The existing NSPS of 43 ng particulate/joule heat input (0.1 lb/10^6 Btu) (2) 22 ng particulate/joule heat input (0.05 lb/10^6 Btu) (3) 13 ng particulate/joule heat input (0.03 lb/10^6 Btu)			
Location	Midwest location - East North Central Region.			
Boiler data				
Capacity factor	Assumed 0.65 for all plants			
Heat rates, flue gas flow rates, and remaining life	Capacity, MW	Heat rate[1], 10^3 joules/kWh (Btu/kWh)	Flue gas[1] flow rate, m^3/sec/MW (acfm/MW)	Remaining life, yr
	25	10,540 (10,000)	1.65 (3,500)	35
	100	10,013 (9,500)	1.58 (3,350)	35
	200	9,700 (9,200)	1.50 (3,175)	35
	500	9,490 (9,000)	1.45 (3,080)	35
	1,000	9,170 (8,700)	1.42 (3,000)	35
Flue gas temperature	Assumed 155°C (310°F) for all plants.			

[1] Detailed Cost Estimates for Advanced Effluent Desulfurization Processes, prepared for Control Systems Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, under Interagency Agreement EPA IAG-134(d) Part A, by G. C. McGlamery, et al., Tennessee Valley Authority, pp. 60,66. May 1974.

Table 2. MODEL PLANT PARAMETERS AND ASSUMPTIONS USED IN THE SULFUR DIOXIDE CONTROL ANALYSIS

Model plant parameters	Characteristics and assumptions
Plant capacities, MW	25, 100, 200, 500, and 1000 (single boilers)
Plant status	New
Coal characteristics	(See Table 3)
SO_2 control requirements	(1) The existing NSPS of 516 ng SO_2/joule heat input (1.2 lb SO_2/MM Btu). (2) 90% of SO_2 removal by FGD on a typical coal of 3.5% sulfur and a typical coal of 7% sulfur. (3) 215 ng SO_2/joule heat input (0.5 lbs. SO_2/MM Btu).
Location	Midwest location - East North Central Region.
Boiler data	
Capacity factor	Assumed 0.65 for all plants
Heat rates, flue gas flow rates, and remaining life	(see below)
Flue gas temperature	Assumed 155°C (310°F) for all plants

Heat rates, flue gas flow rates, and remaining life:

Capacity, MW	Heat rate[1], joules/kWh	(Btu/kWh)	Flue gas[1] flow rate, m^3/sec/MW	(acfm/MW)	Remaining life, yr
25	10,540	(10,000)	1.65	(3,500)	35
100	10,013	(9,500)	1.58	(3,350)	35
200	9,700	(9,200)	1.50	(3,175)	35
500	9,400	(9,000)	1.45	(3,080)	35
1,000	9,170	(8,700)	1.42	(3,000)	35

[1] Detailed Cost Estimates for Advanced Effluent Desulfurization Processes, prepared for Control Systems Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, under Interagency Agreement EPA IAG-134(d) Part A, by G. C. McGlamery, et al., Tennessee Valley Authority, pp. 60,66. May 1974.

Table 2 (continued). MODEL PLANT PARAMETERS AND ASSUMPTIONS USED IN THE SULFUR DIOXIDE CONTROL ANALYSIS

Model plant parameters (August 1980)	Characteristics and assumptions
Operating cost factors	
Raw materials[1]	
Lime cost	$40.20/ton
Limestone cost	$9.10/ton
Pulverized limestone cost	$15.35/ton
Soda ash cost	$105.00/ton
Salt cake credit	$50.00/ton
Sulfuric acid credit	$25.00/ton
Magnesium oxide cost	$185.00/ton
Coke cost	$125.00/ton
Fuel oil cost	$15.00/bbl
Electricity cost	25 mills/kWh
Capital recovery	18.75 percent of total capital investment
Taxes and insurance	4 percent of total capital investment
Sludge disposal	On-site disposal of stabilized sludge
Redundancy requirements	
25 MW	No spare module
100, 200, 500, 1000 MW	1 spare module

[1] Costs were obtained from distributors of the various products and escalated to August 1980 dollars.

Table 3. ANALYSES OF COALS USED AS THE COST ESTIMATING BASIS

Coal type	Total sulfur, %	Pyritic sulfur, %	Ash, %	Heating value, J/g (Btu/lb)
Eastern bituminous	6.39	4.6	14	28,000 (12,000)
Eastern bituminous	3.48	2.49	14	28,000 (12,000)
Western subbituminous	0.8	-	8	23,000 (10,000)
Western lignite	0.4	-	6	19,000 (8,000)
Anthracite	0.8	-	6	31,000 (13,500)

Table 4. PARTICULATE EMISSION CONTROL DEVICE DESIGN PARAMETERS

Control system	Design parameter	Regulation level, ng/J ($lb/10^6$ Btu)			Regulation level, ng/J ($lb/10^6$ Btu)		
		43 (0.1)	22 (0.05)	13 (0.03)	43 (0.1)	22 (0.05)	13 (0.03)
ESP	Type, hot or cold	Cold	Cold	Cold	Hot	Hot	Hot
	SCA, m^2/m^3/sec (ft^2/1000 acfm)	47 (240)	59 (300)	71 (360)	79 (400)	108 (550)	128 (650)
	Temperature, °C (°F)	154 (310)	154 (310)	154 (310)	371 (700)	371 (700)	371 (700)
Fabric filter	Air-to-cloth ratio, $m^3/sec/m^2$ ($acfm/ft^2$)			.01:1 (2:1)			.01:1 (2:1)
Venturi scrubber	L/G ratio, $1/m^3$ (gal/1000 acf)	2 (15)	2 (15)		2 (15)	2 (15)	
	Gas velocity, m/sec (ft/sec)	38 (125)	38 (125)		38 (125)	38 (125)	
	Pressure drop, nm H_2O (in. H_2O)	203 (8)	762 (30)		203 (8)	762 (30)	

Table 5. DESIGN PARAMETERS FOR THE FGD SYSTEMS

Model plant parameters for current NSPS	Characteristics and assumptions				
FGD systems	Lime	Limestone	Double alkali	Sodium solution	Magnesium oxide
Absorber type	TCA[1]	TCA	Tray	Tray	TCA
Number of stages	2	2	2	2	2
Liquid to gas ratio, L/G $1/m^3$ (gal/1000 acf)	5.3 (40)	8.7 (65)	2.7 (20)	1.2 (9)	5.3 (40)
Gas velocity in absorber, m/sec (ft/sec)	3.0 (10)	3.0 (10)	2.4 (8)	2.4 (8)	3.0 (10)
Flue gas temperature at absorber outlet, °C (°F)	52 (125)	52 (125)	52 (125)	52 (125)	52 (125)
Degree of reheat, °C (°F)	28 (50)	28 (50)	28 (50)	28 (50)	28 (50)
Hold tank retention time, min	10	10	6	1	10
Makeup requirement, %	-	-	5	5	7
Byproduct				H_2SO_4, Na_2SO_4	H_2SO_4

1 Turbulent contact absorber

Table 5 (Cont'd). DESIGN PARAMETERS FOR THE FGD SYSTEMS

Model plant parameters for 90 % or greater control	Characteristics and assumptions				
FGD systems	Lime	Limestone	Double alkali	Sodium solution	Magnesium oxide
Absorber type	TCA	TCA	Tray	Tray	TCA
Number of stages	3	3	3	3	3
Liquid to gas ratio, L/G l/m^3 (gal/1000 acf)	8.0 (60)	11.3 (85)	4.0 (30)	1.6 (12)	8.0 (60)
Gas velocity in absorber, m/sec (ft/sec)	3.0 (10)	3.0 (10)	2.4 (8)	2.4 (8)	3.0 (10)
Flue gas temperature at absorber outlet, °C (°F)	52 (125)	52 (125)	52 (125)	52 (125)	52 (125)
Degree of reheat, °C (°F)	28 (50)	28 (50)	28 (50)	28 (50)	28 (50)
Hold tank retention time, min	10	10	6	1	10
Makeup requirement, %	-	-	5	5	7
Byproduct				H_2SO_4, Na_2SO_4	H_2SO_4

system, variations in system load, and the efficiency and flexibility of emission control equipment. If the SO_2 control method is an FGD system, the system must be designed to cope with a higher average sulfur content in the fuel for shorter averaging periods.

For purposes of evaluating the impacts of various averaging times on the costs of compliance, a lime FGD system was costed for plants of three sizes, three types of coal, and for four averaging periods. Coals chosen for analysis are listed in Table 6. Also presented in the table are average sulfur contents for each size plant over the various averaging times. For each size plant, a lime FGD system was costed designed for 90 percent SO_2 removal on the average sulfur content indicated in Table 6. Results of the cost analysis are presented in Tables 7, 8, 9, and 10.

As the results indicate, costs will increase as the averaging time is shortened. The effect is also more significant for smaller units due to the increased variability of sulfur as the quantity used during the averaging time decreases. For instance, in the 3.5 percent sulfur case, reducing the averaging time from 1 year to 3 hours increases capital costs by 4.5 percent for the 500 MW case compared to 4.0 percent for the 1000 MW case. Also as the coal sulfur content decreases, the cost impacts of shorter

Table 6. COAL ANALYSES AND SULFUR VARIABILITY OVER VARIOUS AVERAGING TIMES[1]

Coal type	Plant size, MW	Maximum average sulfur content, %				
		Long-term	Annual	30 days	1 day	3 hours
Eastern bituminous, 14% ash, 28,000 J/g (12,000 Btu/lb)	25	7.00	7.36	8.27	9.36	9.73
	500	7.00	7.23	7.79	8.88	9.23
	1000	7.00	7.22	7.75	8.78	9.19
Eastern bituminous, 14% ash, 28,000 J/g (12,000 Btu/lb)	25	3.50	3.68	4.13	4.68	4.86
	500	3.50	3.62	3.89	4.44	4.61
	1000	3.50	3.61	3.87	4.39	4.59
Western subbituminous 8% ash, 23,000 J/g (10,000 Btu/lb)	25	0.80	0.84	0.96	1.12	1.18
	500	0.80	0.83	0.90	1.05	1.10
	1000	0.80	0.83	0.89	1.03	1.09

[1] Distribution from unit train sampling.

Table 7. COSTS OF A LIME FGD SYSTEM DESIGNED FOR 90 PERCENT SO_2 REMOVAL OVER AN ANNUAL AVERAGING PERIOD

1 Year 90% Control		Plant size					
Sulfur in coal		25 MW		500 MW		1000 MW	
		Capital, $/kW	Annual, mills/kWh	Capital, $/kW	Annual, mills/kWh	Capital $/kW	Annual, mills/kWh
	7.36%	296.10	23.51				
7.0%	7.23%			150.83	11.48		
	7.22%					126.56	9.92
	3.68%	271.40	20.90				
3.5%	3.62%			133.47	9.64		
	3.61%					111.41	8.13
	0.84%	243.24	18.25				
0.8%	0.83%			114.97	7.53		
	0.83%					97.17	6.39

Table 8. COSTS OF A LIME FGD SYSTEM DESIGNED FOR

90 PERCENT SO_2 REMOVAL OVER A 30-DAY AVERAGING PERIOD

30 Days 90% Control		Plant size					
Sulfur in coal		25 MW		500 MW		1000 MW	
		Capital, $/kW	Annual, mills/kWh	Capital, $/kW	Annual, mills/kWh	Capital $/kW	Annual, mills/kWh
	8.27%	307.34	23.96				
7.0%	7.79%			153.39	11.59		
	7.75%					128.34	9.99
	4.13%	278.32	21.17				
3.5%	3.89%			134.86	9.69		
	3.87%					112.47	8.17
	0.96%	246.68	18.39				
0.8%	0.90%			115.62	7.55		
	0.89%					97.58	6.40

Table 9. COSTS OF A LIME FGD SYSTEM DESIGNED FOR 90 PERCENT SO_2 REMOVAL OVER A 24-HOUR AVERAGING PERIOD

24 Hours 90% Control		Plant size					
Sulfur in coal		25 MW		500 MW		1000 MW	
		Capital, $/kW	Annual, mills/kWh	Capital, $/kW	Annual, mills/kWh	Capital $/kW	Annual, mills/kWh
7.0%	9.36% 8.88% 8.78%	319.92	24.47	157.05	11.73	131.56	10.12
3.5%	4.68% 4.44% 4.39%	287.06	21.52	137.66	9.81	114.63	8.26
0.8%	1.12% 1.05% 1.03%	250.84	18.55	115.72	7.56	98.51	6.44

Table 10. COSTS OF A LIME FGD SYSTEM DESIGNED FOR

90 PERCENT SO_2 REMOVAL OVER A 3-HOUR AVERAGING PERIOD

3 Hours 90% Control		Plant size					
Sulfur in coal		25 MW		500 MW		1000 MW	
		Capital, $/kW	Annual, mills/kWh	Capital, $/kW	Annual, mills/kWh	Capital $/kW	Annual, mills/kWh
7.0%	9.73%	322.48	24.55				
	9.23%			157.17	11.73		
	9.19%					132.02	10.13
3.5%	4.86%	289.96	21.63				
	4.61%			139.46	9.87		
	4.59%					115.91	8.30
0.8%	1.18%	252.52	18.61				
	1.10%			119.42	7.70		
	1.09%					98.86	6.45

averaging times decrease. For the 0.8 percent sulfur case the differential capital costs between 1 year and 3 hour averaging times varies from 3.9 percent for the 500 MW case to 1.7 percent for the 1000 MW case. Impacts on annual operating costs are not significant since their costs reflect the average annual sulfur content of the coal.

For this cost study, an averaging time of 3 hours was used as a basis for determining FGD system costs.

Redundancy

In reviewing air pollutant limitations and their cost implications, another consideration is the required operational availability of the control method. The major implication for this study is the availability required of an FGD system meeting a 3-hour average emission limitation. The availability of an FGD system is directly affected by the redundancy built into the system via use of spare components. For purposes of the cost analysis a single spare module was assumed to be required for each boiler with a capacity above 25 MW. This will assure a high level of availability for the system.

Particulate Emission Control Cost Estimates

To analyze the potential cost impact of revisions to particulate emission regulations, three particulate control systems were costed for various size plants at various regulation levels for two coals (specified in Table 3 as Eastern 3.48% S and Western 0.8% S coals). Fabric filters were costed for a regulation level of 13.4 ng/J (0.033 $lb/10^6$ Btu). Cold-side electrostatic precipitators were costed for Eastern high sulfur coal to meet levels of 13 ng/J (0.03 $lb/10^6$ Btu), 22 ng/J (0.05 $lb/10^6$ Btu), and 43 ng/J (0.1 $lb/10^6$ Btu). Hot-side electrostatic precipitators were costed on the Western low sulfur coal to meet these same regulation levels. Venturi scrubbers were costed to meet the present regulation of 43 ng/J and 22 ng/J level. Results of these cost estimates are presented in Table 11.

As the results indicate, the costs of control devices increase as the required emission reduction is increased. Reducing the NSPS from 43 ng/J to 22 ng/J would increase capital costs about 5 percent for a cold side ESP on a 500 MW unit burning Eastern high sulfur coal. For a 500 MW unit on Western low sulfur coal, the capital costs for a hot-side ESP would increase about 30 percent. The annual costs would increase about 5 percent for the high sulfur case and 30 percent for the low sulfur case.

If the regulation were reduced to 13 ng/J, the capital cost of an ESP for the low sulfur case would increase by 54 percent and by 19 percent for the high sulfur case. Annual costs would increase by 53 percent for the low sulfur case

Table 11. COSTS OF PARTICULATE CONTROL ALTERNATIVES

Regulation level	Coal: Sulfur %	Coal: Ash %	Boiler capacity, megawatts	Fabric filters[a]: Capital cost $/kW	Fabric filters[a]: Annual cost, mills/kWh O&M	Fabric filters[a]: Annual cost, mills/kWh Fixed	Electrostatic precipitators: Capital cost, $/kW	Electrostatic precipitators: Annual cost, mills/kWh O&M	Electrostatic precipitators: Annual cost, mills/kWh Fixed	Venturi scrubbers[b]: Capital cost, $/kW	Venturi scrubbers[b]: Annual cost, mills/kWh O&M	Venturi scrubbers[b]: Annual cost, mills/kWh Fixed
13.0 ng/j	0.8	8.0	25				182.20	3.27	5.44			
			100				98.22	1.72	2.93			
			200	69.47	0.37	1.93						
			500	58.45	0.34	1.62	80.71	1.36	2.41			
			1000	53.56	0.33	1.48	73.37	1.24	2.19			
	3.5	14.0	25				91.00	1.84	2.72			
			100				57.32	0.98	1.71			
			200	59.89	0.32	1.65						
			500	51.83	0.29	1.43	31.82	0.54	0.95			
			1000	46.73	0.28	1.30	28.96	0.48	0.87			
22.0 ng/j	0.8	8.0	25				171.40	3.07	5.12	177.08	1.41	6.98
			100				90.67	1.58	2.71	129.47	1.29	5.10
			500				68.45	1.17	2.04	72.84	0.79	2.98
			1000				65.13	1.10	1.94	58.72	0.59	2.27
	3.5	14.0	25				89.80	1.81	2.68	178.48	1.45	7.15
			100				53.16	0.91	1.59	128.10	1.30	5.15
			500				28.21	0.47	0.84	72.63	0.80	3.03
			1000				24.76	0.41	0.74	68.65	0.78	2.87
43.0 ng/j	0.8	8.0	25				134.60	2.49	4.02	111.64	1.38	4.40
			100				76.06	1.32	2.27	101.04	1.25	3.98
			500				52.53	0.89	1.57	58.93	0.76	2.41
			1000				50.15	0.84	1.50	46.07	0.56	1.78
	3.5	14.0	25				91.80	1.82	2.74	112.52	1.42	4.51
			100				51.11	0.87	1.53	99.97	1.26	4.02
			500				26.85	0.45	0.80	58.67	0.77	2.45
			1000				23.61	0.39	0.71	57.21	0.75	2.39

[a] Level examined was 13.4 ng/j

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

and by 19 percent for the high sulfur case. At a regulation level of 22 ng/J, fabric filters appear to be more economical for low sulfur coal application than hot side ESP's. For the 500 MW case, capital costs are 28 percent less for the fabric filter and annual costs are 48 percent less.

Sulfur Dioxide Control Cost Estimates

To analyze the potential economic impact of revisions to the NSPS for SO_2 emissions, various control systems were costed for each of 3 alternative emission levels. The first level examined was the present NSPS of 516 ng/J (1.2 lb/10^6 Btu). For Eastern 3.5 percent sulfur coal, the cases costed included lime, limestone, magnesium oxide, double alkali, and Wellman Lord FGD systems for the 25, 100, 200, 500, and 1000 MW boilers, combined coal cleaning with lime FGD for a 500 MW boiler, and combined coal cleaning with limestone FGD for a 500 MW boiler. For Eastern 7.0 percent sulfur coal, cases costed were lime and limestone FGD systems for 25, 100, 200, 500, and 1000 MW boilers. A lime FGD system was costed for a 500 MW boiler for both anthracite and lignite. Incremental boiler costs were estimated for boilers designed for Eastern low sulfur, Western subbituminous, and lignitic coals versus boilers designed for Eastern high sulfur coal. Costs were also estimated for the transportation of Western coal to the Eastern seaboard (i.e. Boston).

The second SO_2 control level examined was a requirement for 90 percent removal regardless of sulfur content of the coal burned. For the Eastern 3.5 percent sulfur and 7.0 percent sulfur coals, options costed included lime, limestone, magnesium oxide, double alkali, and Wellman Lord FGD systems for the 25, 100, 200, 500 and 1000 MW boilers. Cases costed for Western subbituminous coal were lime and limestone FGD for 25, 200, and 500 MW boilers. A lime FGD system was also costed for anthracite and lignite for a 500 MW boiler.

The third SO_2 emission limitation examined was 215 ng/J (0.5 lb/10^6 Btu). Options evaluated included lime and limestone FGD on Western subbituminous coal. Other options evaluated included combined coal cleaning and lime FGD and combined coal cleaning and limestone FGD on Eastern 7.0 percent sulfur coal.

The costs estimated for each of the options are presented in Table 12.

The incremental cost of going from the 516 nanograms per joule (1.2 lb/10^6 Btu) to the 90 percent control case varied in capital cost from 10-12 percent for 3.5 percent Eastern coal to less than one percent for 7.0 percent Eastern coal. Annualized costs show approximately the same percentage increases. Assuming that power plants currently using

Table 12. COSTS OF SO_2 CONTROL ALTERNATIVES

Case 1: 1.2 lbs/MMBtu

Coal type, % sulfur / Boiler capacity, megawatts	Lime FGD Capital $/kW	Lime FGD O & M	Lime FGD Fixed mills/kWh	Lime FGD Total	Limestone FGD Capital $/kW	Limestone FGD O & M	Limestone FGD Fixed mills/kWh	Limestone FGD Total	Mag-Ox FGD Capital $/kW	Mag-Ox FGD O & M	Mag-Ox FGD Fixed mills/kWh	Mag-Ox FGD Total	Double alkali FGD Capital $/kW	Double alkali FGD O & M	Double alkali FGD Fixed mills/kWh	Double alkali FGD Total	Wellman-Lord FGD Capital $/kW	Wellman-Lord FGD O & M	Wellman-Lord FGD Fixed mills/kWh	Wellman-Lord FGD Total
Eastern, 3.5																				
25	262.76	9.50	10.50	20.00	278.48	9.90	11.13	21.03	409.12	13.47	16.35	29.82	306.00	10.28	12.31	22.59	370.24	12.14	14.79	26.93
100	234.78	5.99	9.38	15.37	265.77	6.41	11.42	17.83	319.66	7.60	12.77	20.37	297.70	7.00	11.89	18.89	290.22	6.35	11.60	17.95
250	174.46	4.68	6.97	11.65	202.46	4.78	8.09	12.87	210.41	5.22	8.41	13.63	194.78	5.11	7.78	12.89	188.91	4.26	7.55	11.81
500	124.93	3.92	4.99	8.91	142.58	3.68	5.70	9.38	156.76	4.18	6.26	10.44	147.09	4.37	5.88	10.25	141.16	3.28	5.64	8.92
1000	103.71	3.34	4.14	7.48	119.02	3.28	4.76	8.04	131.00	3.53	5.23	8.76	119.60	3.72	4.78	8.50	116.05	2.68	4.64	7.32
Eastern, 7.0																				
25	321.08	11.58	12.83	24.41	338.64	12.00	13.53	25.53												
100	290.51	7.92	11.51	19.53	352.58	8.17	14.09	22.26												
200	217.36	5.41	9.68	15.09	252.11	6.30	10.07	16.37												
500	156.34	5.29	6.25	11.54	185.94	5.09	7.43	12.52												
1000	131.59	[illegible]	5.25	10.07	156.53	4.57	6.25	10.82												
Anthracite																				
500																				
Lignite																				
500	96.67	2.29	3.86	6.15																

Coal type, % sulfur / Boiler capacity, megawatts	Incremental boiler cost Capital $/kW	Incremental boiler cost O & M	Incremental boiler cost Fixed mills/kWh	Incremental boiler cost Total	Transportation Capital $/kW	Transportation O & M	Transportation Fixed mills/kWh	Transportation Total
Eastern, 0.8								
25	1.32		0.05	0.05				
200	0.58		0.02	0.02				
500	0.40		0.02	0.02				
Eastern, 3.5								
500								
Western, 0.8 (low rank)								
25	112.00		4.47	4.47				
200	48.75		1.95	1.95				
500	33.80		1.35	1.35				
Western, 0.8 (high rank)								
25	74.00		2.96	2.96				
200	32.15		1.28	1.28				
500	22.30		0.89	0.89				
Western								
Unspecified						17.80		17.08

Coal type, % sulfur / Boiler capacity, megawatts	Combination: Coal cleaning Capital $/kW	Coal cleaning O & M	Coal cleaning Fixed mills/kWh	Coal cleaning Total	Combination: Lime FGD Capital $/kW	Lime FGD O & M	Lime FGD Fixed mills/kWh	Lime FGD Total	Combination: Coal cleaning Capital $/kW	Coal cleaning O & M	Coal cleaning Fixed mills/kWh	Coal cleaning Total	Combination: Limestone FGD Capital $/kW	Limestone FGD O & M	Limestone FGD Fixed mills/kWh	Limestone FGD Total
Eastern, 3.5																
500	15.50	5.42	1.60	7.02	111.32	2.90	4.45	7.35	15.50	5.42	1.60	7.02	126.83	3.00	5.07	8.07

Table 12 (continued). COSTS OF SO_2 CONTROL ALTERNATIVES

Case 2: 90.0% SO_2 removal

Coal type, % sulfur	Lime FGD				Limestone FGD				Mag-Ox FGD				Double alkali FGD				Wellman-Lord FGD			
Boiler capacity, megawatts	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total
Eastern, 3.5																				
25	289.96	10.04	11.59	21.63	307.60	10.46	12.29	22.75	439.40	13.99	17.56	31.55	337.60	10.89	13.49	24.38	395.76	12.49	15.81	28.30
100	259.88	6.51	10.38	16.89	316.67	6.95	12.65	19.60	354.17	8.15	14.15	22.30	329.64	7.63	13.17	20.80	317.53	6.71	12.69	19.40
200	194.23	5.11	7.76	12.87	225.08	5.21	8.99	14.20	233.21	5.63	9.32	14.95	215.57	5.59	8.61	14.20	206.02	4.49	8.23	12.72
500	139.46	4.30	5.57	9.87	160.15	4.05	6.40	10.45	174.60	4.57	6.98	11.55	163.79	4.82	6.54	11.36	154.93	3.49	6.19	9.68
1000	115.91	3.67	4.63	8.30	134.06	3.61	5.36	8.97	146.93	3.85	5.87	9.72	133.76	4.09	5.34	9.43	127.56	2.84	5.10	7.94
Eastern, 7.0																				
25	322.48	11.67	12.88	24.55	339.98	12.06	13.50	25.64	481.56	15.40	19.24	34.64	374.92	12.78	19.98	27.76	417.48	12.85	16.68	29.53
100	291.52	7.98	11.65	19.63	353.70	8.23	14.13	22.36	398.03	9.26	15.90	25.16	364.41	9.32	14.56	23.88	336.49	6.93	13.44	20.37
200	218.09	6.47	8.71	15.18	252.70	6.35	10.10	16.35	264.99	6.76	10.59	17.35	242.43	7.16	9.69	16.85	220.93	4.67	8.83	13.50
500	157.17	5.45	6.28	11.73	186.59	5.15	7.46	12.61	205.81	5.75	8.22	13.97	183.80	6.47	7.34	13.81	169.24	3.79	6.76	10.55
1000	132.02	4.86	5.27	10.13	157.05	4.62	6.27	10.89	173.01	4.86	6.91	11.77	151.11	5.47	6.04	11.51	140.36	3.01	5.61	8.62
Western, 0.8																				
25	252.52	8.52	10.09	18.61	269.16	8.94	10.75	19.69												
200	166.09	3.85	6.64	10.49	192.13	4.12	7.68	11.80												
500	119.42	2.93	4.77	7.70	137.20	3.09	5.48	8.57												
Anthracite																				
500	116.57	2.82	4.66	7.48																
Lignite																				
500	116.71	2.86	4.66	7.52																

Case 3: 215 ng/J (0.5 lb/10^6 Btu)

Coal type, % sulfur	Lime FGD				Limestone FGD				Combination								Combination							
									Coal cleaning				Lime FGD				Coal cleaning				Limestone FGD			
Boiler capacity, megawatts	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total
Western, 0.8																								
25	226.68	8.08	9.06	17.14	241.76	8.46	9.66	18.12																
200	146.68	3.50	5.86	9.36	169.93	3.75	6.79	10.54																
500	105.44	2.66	4.21	6.87	119.95	2.79	4.79	7.58																
Eastern, 7.0																								
25									19.60	8.32	2.46	10.78	285.32	9.83	11.40	21.23	19.60	8.32	2.46	10.78	303.40	10.26	12.12	22.38
200									17.40	7.66	2.26	9.92	190.99	4.95	7.63	12.58	17.40	7.66	2.26	9.92	221.29	5.07	8.84	13.91
500									16.45	7.49	2.21	9.70	136.77	3.93	5.46	9.39	16.45	7.49	2.31	9.70	157.51	3.93	6.29	10.22

Western low sulfur coal do not have to use flue gas desulfurization under the present NSPS, the cost impact of a revised NSPS amounts to the entire investment and annualized cost of control.

It should be noted that while the investment cost of the combination of FGD and coal cleaning is close to that of the 90 percent FGD alone the total annualized costs are 60 percent greater for both the base case and the 215 ng/J (0.5 lb/10^6 Btu) case.

1.0 INTRODUCTION

In support of a program to review New Source Performance Standards (NSPS) for particulate and sulfur dioxide (SO_2) emissions from coal-fired steam generators, the U.S. Environmental Protection Agency (EPA) is preparing estimates of the costs of air pollution control equipment. The program includes cost estimates of the various control alternatives available to meet the present NSPS of 43 ng particulate per joule of heat input (0.1 lb/10^6 Btu) and 516 ng SO_2 per joule of heat input (1.2 lb/10^6 Btu), with comparative cost estimates to meet alternative emission levels of 22 ng particulate per joule heat input (0.05 lb/10^6 Btu), 13 ng particulate per joule heat input (0.03 lb/10^6 Btu), 215 ng SO_2 per joule heat input (0.5 lb/10^6 Btu), and 90 percent reduction of potential SO_2 emissions. EPA has contracted with PEDCo Environmental, Inc. to develop cost estimates for flue gas desulfurization (FGD) systems, physical coal cleaning facilities, electrostatic precipitators (ESP), fabric filters, venturi scrubbers, cost differentials of boilers designed for western subbituminous coals, and transportation of coal from the west to eastern markets for each of the alternative emission levels. Model steam-electric generating plants of various sizes were used as a basis for estimating these costs.

In Section 2 the various emission control alternatives considered in the study are described. Section 3 presents the cost estimates for the particulate emission control devices. SO_2 emission control alternatives cost estimates are presented in Section 4. In Section 5, the concept of averaging time and its effect on emission control requirements is presented. Section 6 describes the combination of physical coal cleaning and FGD as an SO_2 emission control alternative.

2.0 EMISSION CONTROL ALTERNATIVES TO MEET REVISED NSPS

The revisions to the NSPS for particulate emissions being considered in this study are 22 ng/J (0.05 lb/10^6 Btu) and 13 ng/J (0.03 lb/10^6 Btu). Control devices available to attain these emission levels are electrostatic precipitators (ESP) and fabric filters. Wet venturi scrubbers may be utilized to attain the present NSPS level of 43 ng/J (0.1 lb/10^6 Btu) and also the 22 ng/J (0.05 lb/10^6 Btu) particulate emission level.

The alternative NSPS being considered for SO_2 emissions are 215 ng/J (0.5 lb/10^6 Btu) and 90 percent control.

Control techniques available to meet these alternative standards are FGD and combined physical coal cleaning and FGD. To meet the present NSPS of 1.2 lb SO_2/10^6 Btu, low sulfur coal alone may meet the standard. But any new standard based on a percentage reduction precludes the use of low sulfur coal without FGD.

2.1 PARTICULATE EMISSION CONTROL ALTERNATIVES

This study considers 3 particulate control devices: ESP's, fabric filters, and venturi scrubbers. The following sections describe these control devices and their capabilities.

2.1.1 Electrostatic Precipitators

Electrostatic precipitation is a physical process for the removal of suspended particulates from a gas stream. The particles are charged electrically and separated from the gas streams by contact with collecting surfaces having the opposite electrical charge. The agglomerated dust is periodically removed from the collecting surface by vibrating or rapping the surface. This dust drops from the electrical zone to hoppers for ultimate disposal. Commercially available precipitators include sections of collecting plates, discharge electrodes, rapping devices, dust hoppers, enveloping insulation and casing, and the appropriate electrical energizing equipment.

Current ESP units, both those treating flue gas from a heat source and those collecting particulates emitted from processes are greatly improved from those designed as recently as the middle 1960's. This can be attributed to stringent regulations, more accurate techniques for performance prediction, utilization of computers for calculations, superior construction materials, high quality auxiliary components and the availability of a useful base of recent ESP performance experience.

On utility coal-fired boiler applications, ESP's can achieve emission levels as low as 13 ng of particulate per joule of heat input (0.03 lbs/10^6 Btu).

2.1.2 Fabric Filters

Fabric filters may be used for the removal of suspended particles from gas streams. The particles are removed by passage of the gas stream through woven cloth or fiberglass which prevent particles from passing through. The agglomerated dust is periodically removed from the fabric by mechanically shaking the fabric or by blowing air in a reverse direction through the fabric. The dust is collected in hoppers at the bottom of the filter for ultimate disposal. The system consists of bags, shaking devices or a reverse air system, dust hoppers, and enveloping casing and insulation.

On utility coal-fired boiler applications, fabric filters can achieve emission levels of about 13 ng particulate per joule of heat input (0.03 lb/10^6 Btu).

2.1.3 Venturi Scrubbers

Venturi scrubbers are effective in removal of suspended particles from gas streams. The particles are removed by contact with atomized water droplets and subsequent removal of the water droplets and wetted particles. The collected water and particulate matter must be treated to prevent water pollution. Generally the efficiency of a venturi scrubber increases with pressure drop.

The system consists of the scrubber, pumps, an entrainment separator and a fan to overcome the pressure drop.

On utility coal-fired boiler applications, venturi scrubbers can achieve emission levels of about 43 ng/J (0.1 lbs per million Btu) of particulate at moderate pressure drops (10-20 inches H_2O). At greater pressure drops (20-30 inches H_2O), venturi scrubbers can achieve emission levels of 22 ng/J (0.05 lb/10^6 Btu).

2.2 SULFUR DIOXIDE EMISSION CONTROL ALTERNATIVES

Several methods exist by which SO_2 emissions may be reduced to levels required to comply with NSPS. In this study the following control technologies were considered: flue gas desulfurization (FGD) and coal cleaning in combination with FGD. The following sections describe these control technologies and their capabilities.

2.2.1 Flue Gas Desulfurization (FGD)

Several FGD processes have been developed for the removal of sulfur dioxide from flue gases before the gases are discharged to the atmosphere. Flue gases are brought into contact with a chemical absorbent in a unit described as an absorber. The absorbent reacts chemically with SO_2 to produce a slurry containing dissolved or solidified sulfur compounds. FGD processes are classified as regenerable or nonregenerable, based on whether the SO_2 is separated from the absorbent as a by-product or discarded along with the absorbent as waste. Nonregenerable processes produce a sludge that requires disposal in an environmentally sound manner. Regenerable processes include additional steps to process the sulfur into liquid SO_2, sulfuric acid, or elemental sulfur.

Most FGD processes in use in the United States are nonregenerable, using lime or limestone for scrubbing. A recirculating alkaline slurry of lime or limestone in water is contacted with SO_2 in the gas stream. The slurry reacts with the SO_2 to form various sulfite and sulfate salts. The salts are removed from the water by means of settlers, clarifiers, or filters. The sludge produced is either chemically stabilized and disposed of as an inert landfill material or stored as an unstabilized sludge in a clay-lined pond.

The regenerable processes offer certain advantages over the nonregenerable ones. No solid waste is accumulated, and resulting by-products may have a market value. Also, total waste stream quantities are significantly reduced. Among the regenerable processes the most common are the sodium solution scrubbing (Wellman-Lord), magnesium oxide slurry scrubbing (Mag-Ox), and catalytic oxidation (Cat-Ox) processes. The Wellman-Lord process absorbs SO_2 in a sodium sulfite/bisulfite solution, which is then heated in a separate vessel to liberate a gas containing SO_2 in a high concentration, which is further processed into commercial grade SO_2, sulfuric acid, or elemental sulfur. In the Mag-

Ox process, dilute magnesium oxide slurry is used as the scrubbing absorbent. The spent slurry is regenerated, and the SO_2 is converted into commercial-grade sulfuric acid. The regenerated solids are recycled for reuse. In the Cat-Ox process SO_2 is directly removed by converting it catalytically into sulfuric acid. Regenerable processes require the utilities to enter the chemical manufacturing business, and the utilities must then be staffed with people who are able to compete with established chemical producers.

FGD systems can generally be designed to provide SO_2 removal efficiencies of 80 to 95 percent under most conditions of practical operation.

2.2.2 Combined Physical Coal Cleaning and Flue Gas Desulfurization

Physical coal cleaning entails the use of specially designed equipment that separates coal from associated minerals, clay, slate, and other impurities. These separations are based on differences in the physical properties of coal and its impurities, such as density, surface characteristics, and size and shape of the particles to some extent. Sulfur occurs in coal in three forms: mineral sulfur (pyrite), organically bound sulfur, and sulfate sulfur. The pyritic form of sulfur is the only form removable by coal washing techniques.

As much as 80 percent of the pyritic sulfur can be removed by coal washing. The pyrite content of coal accounts for 20 to 80 percent of the total sulfur content, depending on the particular coal analysis.

The first step in coal preparation is size reduction. In a conventional coal preparation plant, incoming coal is coarsely crushed to a top (largest) size of about 1-1/2 inches. Coarse grinding minimizes the quantity of fine coal. The degree of size reduction depends on the type of coal cleaning operation and the hardness of the coal. Grinding liberates mineral impurities associated with the coal. The ground coal is passed over screens for separation into various size fractions.

The coarse fractions of the ground coal (down to 1/4 inch) can be cleaned in jigs, heavy-media equipment, air tables, and depending on the top size, Deister tables. Although these coarse coal cleaning processes operate on different principles, all are designed to remove mineral matter (ash) from coal.

The fine coal circuit uses heavy-media cyclones, Deister tables, and froth flotation equipment for cleaning. Cyclones and tables are effective for sizes down to 100 mesh; froth flotation systems are required for cleaning finer particles.

The design of coal preparation circuitry must be based on expert analysis of detailed coal washability data and on practical experience with the various unit operations. The key factor in satisfactory performance of a coal preparation plant is the degree to which the coal samples used in the washability test are representative of the total coal seam.

Physical coal cleaning alone is unlikely to produce coal complying with NSPS. Further reduction in SO_2 is usually necessary to attain levels of 1.2 lb $SO_2/10^6$ Btu or lower. This can be achieved by using an FGD system on the boiler using cleaned coal.

3.0 PARTICULATE CONTROL SYSTEM COSTS

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

To present unencumbered cost estimates and illustrate the impact of site and process factors on total capital and annualized costs of particulate control systems, a model plant approach was used. The following sections define the model plants, the cost methodology, and present the results of the cost estimates.

3.1 COST ELEMENTS

The capital cost of a particulate control system is composed of direct and indirect costs incurred up to the successful commissioning date of the facility. Direct costs include the cost of various equipment items and the labor and material required for installing the equipment items and interconnecting the system. Indirect costs are costs that are necessary for the overall facility but cannot be attributed to a specific equipment item. Indirect costs include such items as freight, spares, interest, taxes, etc.

Operating costs of a facility include labor, raw materials, and utilities required to operate the system on a day-to-day basis. These costs include such items as electricity, water, operating labor, etc.

A brief description of the capital and annual operating cost components and the procedure used to obtain their values is presented in this section.

3.1.1 Capital Costs

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

Direct Costs

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

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

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

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

The direct capital costs of a venturi scrubber include the purchase and installation of equipment including the scrubber, pumps, circulation tanks, tie-in ducting, foundations and support, and an ash disposal system.

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

Indirect Costs

The indirect costs of particulate control systems include the following:

Interest accrued during construction on borrowed capital.

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

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

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

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

<u>Taxes</u>: includes sales, franchise, property, and excise taxes.

<u>Spare parts</u>: (stocked to permit maximum process availability): includes pumps, valves, controls, special piping and fittings, instruments, and similar items.

<u>Shakedown</u>: includes the costs associated with the system start-up.

<u>Contractor's fee and expenses</u>: includes costs for field labor payroll; supervision field office; administrative personnel; construction offices; temporary roadways; railroad trackage; maintenance and welding shops; parking lot; communications; temporary piping and electrical and sanitary facilities; rental equipment; unloading and storage of materials; travel expenses; permits; licenses; taxes; insurance; overhead; legal liabilities; field-testing of equipment; start-up; labor relations.

<u>Contingency costs</u>: includes those resulting from malfunctions, equipment design alterations, and similar unforeseen sources.

<u>Land cost</u>: includes only the cost of the land required for sludge disposal. The cost of land for installing equipment items is accounted for in the installation factors.

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

3.1.2 Annual Operating Costs

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

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

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

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

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

3.1.3 Annual Revenue Requirements

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

The annual fixed charges are classified under four cost components: depreciation, taxes, insurance, and capital costs. The component costs are summed to obtain the total fixed changes.

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

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

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

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

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

3.2 COST ESTIMATING APPROACH

A model plant approach was used in estimating the costs of particulate control on new coal-fired boilers. Typical plants were defined with characteristics intended to be representative of the electric utility industry. Characteristics of the model plants are presented in Table 3-1. Analyses of the coals used in the calculation of costs are given in Table 3-2.

Table 3-1. MODEL PLANT PARAMETERS AND ASSUMPTIONS

USED IN THE PARTICULATE CONTROL ANALYSIS

Model plant parameters	Characteristics and assumptions
Plant capacities, MW	25, 100, 200, 500, and 1000 (single boilers)
Plant status	New
Coal characteristics	(See Table 3-2)
Particulate control requirements	(1) The existing NSPS of 43 ng particulate/joule heat input (0.1 lb/10^6 Btu) (2) 22 ng particulate/joule heat input (0.05 lb/10^6 Btu) (3) 13 ng particulate/joule heat input (0.03 lb/10^6 Btu)
Location	Midwest location - East North Central Region.
Boiler data	
Capacity factor	Assumed 0.65 for all plants
Heat rates, flue gas flow rates, and remaining life	

Heat rates, flue gas flow rates, and remaining life:

Capacity, MW	Heat rate[1], 10^3 joules/kWh (Btu/kWh)	Flue gas[1] flow rate, m^3/sec/MW (acfm/MW)	Remaining life, yr
25	10,540 (10,000)	1.65 (3,500)	35
100	10,013 (9,500)	1.58 (3,350)	35
200	9,700 (9,200)	1.50 (3,175)	35
500	9,490 (9,000)	1.45 (3,080)	35
1,000	9,170 (8,700)	1.42 (3,000)	35

Model plant parameters	Characteristics and assumptions
Flue gas temperature	Assumed 155°C (310°F) for all plants.

[1] Detailed Cost Estimates for Advanced Effluent Desulfurization Processes, prepared for Control Systems Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, under Interagency Agreement EPA IAG-134(d) Part A, by G. C. McGlamery, et al., Tennessee Valley Authority, pp. 60,66. May 1974.

Table 3-2. COAL ANALYSES USED IN CALCULATING PARTICULATE CONTROL COSTS

Coal type	% Sulfur, by wt.	Ash, % by wt.	Heating value, 10^3 joules/kg	(Btu/lb)
Eastern bituminous	3.5	14	5,737	(12,000)
Western subbituminous	0.8	8	4,781	(10,000)

The model plants were selected to incorporate four varying cost factors: plant size (capacity), particulate control system type, coal analysis, and degree of particulate control required. Boiler sizes of 25, 100, 200, 500, and 1000 MW were selected to cover the range of new coal-fired utility boilers.

These regulation levels were chosen for the analysis in order to determine the economic impact of tightening the NSPS for particulate emissions from utility coal-fired boilers. Levels examined were 43 ng/J (0.1 lb/10^6 Btu), 22 ng/J (0.05 lb/10^6 Btu), and 13 ng/J (0.03 lb/10^6 Btu). Three types of control devices were costed according to the capabilities of the control device.

Electrostatic precipitators were costed to meet all three regulation levels. Design parameters used for the ESP's are presented in Table 3-3. These parameters were specified by EPA based on typical design for the particular coal types.

Table 3-3. PARTICULATE EMISSION CONTROL DEVICE DESIGN PARAMETERS

Control system	Design parameter	Regulation level, ng/J ($lb/10^6$ Btu)			Regulation level, ng/J ($lb/10^6$ Btu)		
		43 (0.1)	22 (0.05)	13 (0.03)	43 (0.1)	22 (0.05)	13 (0.03)
ESP	Type, hot or cold	Cold	Cold	Cold	Hot	Hot	Hot
	SCA, m^2/m^3/sec (ft^2/1000 acfm)	47 (240)	59 (300)	71 (360)	79 (400)	108 (550)	128 (650)
	Temperature, °C (°F)	154 (310)	154 (310)	154 (310)	371 (700)	371 (700)	371 (700)
Fabric filter	Air-to-cloth ratio, $m^3/sec/m^2$ ($acfm/ft^2$)			.01:1 (2:1)			.01:1 (2:1)
Venturi scrubber	L/G ratio, $1/m^3$ (gal/1000 acf)	2 (15)	2 (15)		2 (15)	2 (15)	
	Gas velocity, m/sec (ft/sec)	38 (125)	38 (125)		38 (125)	38 (125)	
	Pressure drop, nm H_2O (in. H_2O)	203 (8)	762 (30)		203 (8)	762 (30)	

Fabric filters were costed only to meet the 13 ng/J regulation level. Design parameters for the fabric filters are also presented in Table 3-3. These are based on data obtained from fabric filter vendors. Venturi scrubbers were costed to meet the 43 ng/J level and the 22 ng/J level with the costs reflective of venturis used conjunction with a flue gas desulfurization system. Design parameters for the venturi scrubbers are presented in Table 3-3. These are based on data from vendors and designs used at utility plants. The two coal types presented in Table 3-2 were used in each case.

3.3 MODEL PLANT COSTS

A summary of the results of the cost analysis for particulate control is presented in Table 3-4. The costs are in August 1980 dollars and include escalation through project completion. The escalation rate used was 7.5 percent per year.

The results indicate that for a particular control device, costs increase as the emission limit is lowered. At the 43 ng/J limit, ESP's are more economical on high sulfur coal than venturi scrubbers, while venturis are more economical on low sulfur coal applications.

If the emission limitation were 22 ng/J, the capital costs of a cold-side ESP on high sulfur coal would increase about 5 percent for a 500 MW unit, while the capital costs

Table 3-4. COSTS OF PARTICULATE CONTROL ALTERNATIVES

Regulation level	Coal: Sulfur %	Coal: Ash %	Boiler capacity, megawatts	Fabric filters[a]: Capital cost $/kW	Fabric filters[a]: Annual cost, mills/kWh O&M	Fabric filters[a]: Annual cost, mills/kWh Fixed	Electrostatic precipitators: Capital cost, $/kW	Electrostatic precipitators: Annual cost, mills/kWh O&M	Electrostatic precipitators: Annual cost, mills/kWh Fixed	Venturi scrubbers[b]: Capital cost, $/kW	Venturi scrubbers[b]: Annual cost, mills/kWh O&M	Venturi scrubbers[b]: Annual cost, mills/kWh Fixed
13.0 ng/j	0.8	8.0	25				182.20	3.27	5.44			
			100				98.22	1.72	2.93			
			200	69.47	0.37	1.93						
			500	58.45	0.34	1.62	80.71	1.36	2.41			
			1000	53.56	0.33	1.48	73.37	1.24	2.19			
	3.5	14.0	25				91.00	1.84	2.72			
			100				57.32	0.98	1.71			
			200	59.89	0.32	1.65						
			500	51.83	0.29	1.43	31.82	0.54	0.95			
			1000	46.73	0.28	1.30	28.96	0.48	0.87			
22.0 ng/j	0.8	8.0	25				171.40	3.07	5.12	177.08	1.41	6.98
			100				90.67	1.58	2.71	129.47	1.29	5.10
			500				68.45	1.17	2.04	72.84	0.79	2.98
			1000				65.13	1.10	1.94	58.72	0.59	2.27
	3.5	14.0	25				89.80	1.81	2.68	178.48	1.45	7.15
			100				53.16	0.91	1.59	128.10	1.30	5.15
			500				28.21	0.47	0.84	72.63	0.80	3.03
			1000				24.76	0.41	0.74	68.65	0.78	2.87
43.0 ng/j	0.8	8.0	25				134.60	2.49	4.02	111.64	1.38	4.40
			100				76.06	1.32	2.27	101.04	1.25	3.98
			500				52.53	0.89	1.57	58.93	0.76	2.41
			1000				50.15	0.84	1.50	46.07	0.56	1.78
	3.5	14.0	25				91.80	1.82	2.74	112.52	1.42	4.51
			100				51.11	0.87	1.53	99.97	1.26	4.02
			500				26.85	0.45	0.80	58.67	0.77	2.45
			1000				23.61	0.39	0.71	57.21	0.75	2.39

[a] Level examined was 13.4 ng/j.
[b] Costs are for venturis as an integral part of a flue gas desulfurization system.

of a hot-side ESP on Western low sulfur coal would increase about 30 percent. Annual costs would be similarly affected, with increases of 5 percent and 30 percent for the cold-side and hot-side applications respectively.

If the regulation level were reduced from 43 ng/J to 13 ng/J, the capital cost of a hot-side ESP on low sulfur coal would increase by 54 percent for the 500 MW case while the cost of a cold-side ESP on high sulfur coal would increase by 19 percent. Annual costs would be increased by 53 percent for the low sulfur case and by 19 percent for the high sulfur case. For this case, the most economical option on low sulfur coal is a fabric filter. Compared to a hot-side ESP, a fabric filter on a 500 MW boiler burning Western low sulfur coal costs 28 percent less with respect to capital costs, and 48 percent less with respect to annual costs.

Samples of detailed cost breakdowns are included in Appendix A.

3.4 ENERGY PENALTIES

The energy penalty must be considered when calculating the costs of emission control systems. Electrical power consumption by the emission control process reduces the net amount of power generated and additional Btu's are required to produce a net kilowatt-hour of electricity.

The additional power-generating capacity required to compensate for the power used by the emission control system evaluated is listed as a capacity penalty. This penalty is discussed in Subsection 3.4.1. Subsection 3.4.2 discusses the energy penalty which represents the increased number of Btu's required to produce a net kilowatt-hour of electricity. These penalties are expressed both as a percentage and as an additional operating cost in mills/kWh.

3.4.1 Emission Control Capacity Penalties

Particulate emission control methods cause losses in net generation by a power plant that sometimes require the addition of generation capacity. Factors that affect the cost of diverting a portion of a utility's electric generating capacity to supply the energy requirements of environmental control equipment or to replace lost capacity are listed below:

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

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

C. System capacity in MW.

D. Annual load growth of the system.

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

F. Reserve capacity requirement:

   1. Unit reliability by type of unit
   2. Unit reliability by size of unit
   3. Shape of load curve
   4. Mix of generating capacity
   5. Maintenance and overhaul

G. Capability of interconnections.

H. Potential for interchange purchases and sales:

   1. Short-term firm
   2. Economy transactions

I. Availability of unit participation.

J. Cost per kW of added generating capacity:

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

K. Cost and availability of fuels.

L. Load characteristics:

   1. Load factor
   2. Relative magnitude of monthly peak loads

M. Mix of generating plant capacity, present and future.

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

The costs presented in Section 3.3 do not include the costs of replacement capacity but do include the costs of purchased power which reflects the recovery of capital costs of generating units supplying the power. Values of the capacity losses due to the control options evaluated are presented in Table 3-5 expressed as a percentage of the plants gross generating capacity.

3.4.2 Emission Control Energy Penalty

The energy penalties associated with particulate emission control devices vary depending upon the control method

Table 3-5. CAPACITY AND ENERGY PENALTIES ASSOCIATED WITH PARTICULATE CONTROL ALTERNATIVES EXPRESSED AS A PERCENTAGE OF GROSS OUTPUT

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

[a] Level examined was 13.4 ng/j

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

used. Energy is consumed by fans, motors, pumps, and in the case of an ESP, the electrical energization of the collecting surfaces. The energy penalty associated with particulate control methods is identical to the capacity penalty since no external energy is required for reheat. Table 3-5 presents these penalties as a percentage of the plants gross generating capacity. Table 3-6 presents the energy penalty as an annualized charge in mills/kWh.

3.5 COST COMPARISON

The costs developed by PEDCo in this study were based on information obtained from vendors of ESP's and from utilities having ESP's installed on coal-fired boilers. In a report entitled "Electrostatic Precipitator Costs for Large Coal-fired Steam Generators" the Industrial Gas Cleaning Institute (IGCI) has published costs for ESP's on coal-fired boilers. The IGCI costs will be compared with those obtained in this study for purposes of clarifying any differences in the cost estimating procedure.

Table 3-7 presents a detailed breakdown of costs developed by PEDCo and by IGCI for a cold-side ESP on a 500 MW boiler burning high sulfur (3.5%) coal. The ESP's are designed to meet a 13 ng/J (0.03 lb/10^6 Btu) regulation level. The IGCI costs are interpolated from costs for a 200 MW unit and a 700 MW unit or a straight-line basis.

Table 3-6. ENERGY PENALTIES ASSOCIATED WITH PARTICULATE CONTROL ALTERNATIVES EXPRESSED IN MILLS PER KILOWATT HOUR

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

[a] Level examined was 13.4 ng/j

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

Table 3-7. COMPARATIVE CAPITAL COSTS FOR A COLD-SIDE ESP ON A 500 MW BOILER

Cost Item	PEDCo	IGCI*
ESP	$ 4,669,285	$ 8,247,863
Ash Handling	$ 1,755,274	$ 153,530
Ducting	$ 1,234,321	
Direct Total	$ 7,658,880	$ 8,401,393
Indirect Costs	$ 2,584,872	$ 659,070
Contingency	$ 2,048,751	$ 190,804
Turnkey Cost	$12,292,503	$ 9,251,267

* Totals interpolated on straight line basis from IGCI figures for 200 and 700 MW boilers.

As seen in the table, the main difference between the cost estimates is in the indirect charges and the contingency. These charges are calculated as a fixed percentage of direct capital costs based on assumptions made by the organization making the estimate. PEDCo's cost estimating procedure is designed to predict costs in the ± 20 percent accuracy range based on non-site-specific information. For this type of estimate, indirect costs are calculated as 33.75 percent of the direct costs and the contingency is calculated as 20 percent of the sum of direct and indirect costs. IGCI uses about 8 percent of direct costs for indirect costs and about 2 percent of direct and indirect costs for a contingency. These values appear to be very low for non-site-specific estimates.

The difference in the ESP costs as shown is about 10 percent which could be accounted for by the interpolation used to obtain the IGCI costs. A straight-line interpolation would produce higher costs than actual since costs do vary exponentially with size. It should also be noted that IGCI does not break out their cost estimates the same as PEDCo, so the most meaningful number for comparison is the total direct costs.

4.0 SO_2 EMISSION CONTROL SYSTEM COSTS

The capital and annualized costs of sulfur dioxide control systems can vary depending on several factors. Factors of major cost impact are boiler size and capacity factor; type of SO_2 control system; sulfur content and heating value of the coal; maximum allowable SO_2 emission rate; boiler status (new or retrofit installation); replacement power requirements and byproduct disposal requirements.

To present unencumbered cost estimates and illustrate the impact of site and process factors on total capital and annualized costs of SO_2 control systems, a model plant approach was used. The following sections define the model plants, the cost methodology, and present the results of the cost estimates.

4.1 COST ELEMENTS

The capital cost of a SO_2 control system is composed of direct and indirect costs incurred up to the successful commissioning date of the facility. Direct costs include the cost of various equipment items and the labor and material required for installing the equipment items and interconnecting the system. Indirect costs are costs that are necessary for the overall facility but cannot be attributed to a specific equipment item. Indirect costs include such items as freight, spares, interest, taxes, etc.

Operating costs of a facility include labor, raw materials, and utilities required to operate the system on a day-to-day basis. These costs include such items as electricity, water, operating labor, etc.

A brief description of the capital and annual operating cost components and the procedure used to obtain their values is presented in this section.

4.1.1 Capital Costs

A discussion of capital costs for SO_2 control systems follows under the headings "Direct Costs" and "Indirect Costs."

Direct Costs

The "bought-out" cost of the equipment and the cost of installing it are considered direct costs. Installation costs also include the interconnection of the system, which involves piping, electrical, and other work for commissioning the system. Installation of the equipment includes foundations, supporting structures, enclosures, piping, ducting, control panels, instrumentation, insulation, painting and other similar items. Costs for interconnection of the various SO_2 control equipment involve site development, construction of access roads and walkways, and the establishment of rail, barge, or truck facilities. The cost of administrative facilities is also considered as a part of the direct costs.

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

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

Direct capital costs for an FGD system include the purchase and installation of equipment including absorbers, fans and motors, reheaters, soot blowers, pumps, tanks, agitators, raw material preparation and storage equipment, byproduct dewatering equipment, sludge disposal or byproduct recovery facilities, foundations, and support. The components vary depending on the type of absorbent used in the system.

Direct capital costs for a physical coal cleaning facility include the purchase and installation of equipment including crushers, conveyors, tanks, vessels, cyclones, screens, centrifuges, sieves, classifiers, bins, filters, and a thermal dryer.

Indirect Costs

The indirect costs of SO_2 control systems include the following:

- Interest accrued during construction on borrowed capital.

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

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

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

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

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

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

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

Contractor's fee and expenses: includes costs for field labor payroll; supervision field office; administrative personnel; construction offices; temporary roadways; railroad trackage; maintenance and welding shops; parking lot; communications; temporary piping and electrical and sanitary facilities; rental equipment; unloading and storage of materials; travel expenses; permits; licenses; taxes; insurance; overhead; legal liabilities; field-testing of equipment; start-up; labor relations.

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

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

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

4.1.2 Annual Operating Costs

Generally calculated on an annual basis, the operating costs of an SO_2 control system are comprised of:

Utilities: includes water for slurries, cooling, and process use; electricity for pumps, fans, valves, lighting, and controls; and fuel or steam for reheat if required.

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

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

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

4.1.3 Annual Revenue Requirements

The capital investment of a pollution control system is generally translated into annual fixed charges. These charges, along with the annual operating costs, represent the total revenue requirement of an SO_2 control system.

The annual fixed charges are classified under four cost components: depreciation, taxes, insurance, and capital costs. The component costs are as follows:

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

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

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

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

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

4.2 COST ESTIMATING APPROACH

A model plant approach was used in estimating the costs of SO_2 control on new coal-fired boilers. Typical plants were defined with characteristics intended to be representative of the electric utility industry. Characteristics of the model plants are presented in Table 4-1. Analyses of the coals used in the calculation of costs are given in Table 4-2.

The model plants were selected to incorporate four varying cost factors: plant size (capacity), SO_2 control system type, coal analysis, and degree of SO_2 control required. Boiler sizes of 25, 100, 200, 500, and 1000 MW were selected to cover the range of new coal-fired utility boilers.

Three regulation levels were examined in the analysis in order to determine the economic effects of more stringent

Table 4-1. MODEL PLANT PARAMETERS AND ASSUMPTIONS USED IN THE SULFUR DIOXIDE CONTROL ANALYSIS

<table>
<tr><th>Model plant parameters</th><th>Characteristics and assumptions</th></tr>
<tr><td>Plant capacities, MW</td><td>25, 100, 200, 500, and 1000 (single boilers)</td></tr>
<tr><td>Plant status</td><td>New</td></tr>
<tr><td>Coal characteristics</td><td>(See Table 4-2)</td></tr>
<tr><td>SO_2 control requirements</td><td>(1) The existing NSPS of 516 ng SO_2/joule heat input (1.2 lb SO_2/MM Btu).
(2) 90% of SO_2 removal by FGD on a typical coal of 3.5% sulfur and a typical coal of 7% sulfur.
(3) 215 ng SO_2/joule heat input (0.5 lbs. SO_2/MM Btu).</td></tr>
<tr><td>Location</td><td>Midwest location - East North Central Region.</td></tr>
<tr><td>Boiler data</td><td></td></tr>
<tr><td>Capacity factor</td><td>Assumed 0.65 for all plants</td></tr>
<tr><td>Heat rates, flue gas flow rates, and remaining life</td><td>
<table>
<tr><th>Capacity, MW</th><th>Heat rate[1], joules/kWh (Btu/kWh)</th><th>Flue gas[1] flow rate, m^3/sec/MW (acfm/MW)</th><th>Remaining life, yr</th></tr>
<tr><td>25</td><td>10,540 (10,000)</td><td>1.65 (3,500)</td><td>35</td></tr>
<tr><td>100</td><td>10,013 (9,500)</td><td>1.58 (3,350)</td><td>35</td></tr>
<tr><td>200</td><td>9,700 (9,200)</td><td>1.50 (3,175)</td><td>35</td></tr>
<tr><td>500</td><td>9,400 (9,000)</td><td>1.45 (3,080)</td><td>35</td></tr>
<tr><td>1,000</td><td>9,170 (8,700)</td><td>1.42 (3,000)</td><td>35</td></tr>
</table>
</td></tr>
<tr><td>Flue gas temperature</td><td>Assumed 155°C (310°F) for all plants</td></tr>
</table>

[1] Detailed Cost Estimates for Advanced Effluent Desulfurization Processes, prepared for Control Systems Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, under Interagency Agreement EPA IAG-134(d) Part A, by G. C. McGlamery, et al., Tennessee Valley Authority, pp. 60,66. May 1974.

Table 4-1 (continued). MODEL PLANT PARAMETERS AND ASSUMPTIONS USED IN THE SULFUR DIOXIDE CONTROL ANALYSIS

Model plant parameters (August 1980)	Characteristics and assumptions
Operating cost factors	
Raw materials[1]	
Lime cost	$40.20/ton
Limestone cost	$9.10/ton
Pulverized limestone cost	$15.35/ton
Soda ash cost	$105.00/ton
Salt cake credit	$50.00/ton
Sulfuric acid credit	$25.00/ton
Magnesium oxide cost	$185.00/ton
Coke cost	$125.00/ton
Fuel oil cost	$15.00/bbl
Electricity cost	25 mills/kWh
Capital recovery	18.75 percent of total capital investment
Taxes and insurance	4 percent of total capital investment
Sludge disposal	On-site disposal of stabilized sludge
Redundancy requirements	
25 MW	No spare module
100, 200, 500, 1000 MW	1 spare module

[1] Costs were obtained from distributors of the various products and escalated to August 1980 dollars.

Table 4-2. ANALYSES OF COALS USED AS THE COST ESTIMATING BASIS

Coal type	Total sulfur, %	Pyritic sulfur, %	Ash, %	Heating value, J/g (Btu/lb)
Eastern bituminous	6.39	4.6	14	28,000 (12,000)
Eastern bituminous	3.48	2.49	14	28,000 (12,000)
Western subbituminous	0.8	-	8	23,000 (10,000)
Western lignite	0.4	-	6	19,000 (8,000)
Anthracite	0.8	-	6	31,000 (13,500)

NSPS for SO_2 emissions for coal-fired utility boilers. Levels examined were 516 ng/J (1.2 lb/10^6 Btu), 215 ng/J (0.5 lb/10^6 Btu), and 90 percent reduction of SO_2 emissions regardless of the level of the uncontrolled emissions. Control technologies evaluated varied by control level and by coal type. Table 4-3 presents a summary of the cases costed in this analysis.

Other important considerations in control system costs are redundancy in the control system and the averaging time over which a particular emission level must be attained. For purposes of this study, FGD systems on units larger than 25 MW were assumed to require a single spare module including pumps, tanks, and associated equipment. The cost implications of requiring a spare module are presented in Appendix B.

The averaging time over which an FGD system must meet the required SO_2 limitation was assumed as 3 hours for this cost study. Section 5 of this report discusses the implications of averaging time.

The design parameters used for FGD systems in the analysis are presented in Table 4-4. The parameters were developed based on review of existing FGD installations and by contacts with the manufacturers of the various FGD systems.

Table 4-3. SUMMARY OF OPTIONS COSTED

	Eastern 7.0% Sulfur Coal																				
	Lime			Lime stone			Well-man Lord			Double alkali			Mag-nesium oxide			Coal clean-ing lime			Coal clean-ing lime-stone		
Megawatts	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu
25	X	X		X	X			X			X			X				X			X
100	X	X		X	X			X			X			X							
200	X	X		X	X			X			X			X				X			X
500	X	X		X	X			X			X			X				X			X
1000	X	X		X	X			X			X			X							

	Eastern 3.5% Sulfur Coal																							
	Lime			lime-stone			Well-man Lord			Double alkali			Mag-nesium oxide			Low sulfur coal			Coal clean-ing lime			Coal clean-ing lime-stone		
Megawatts	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu
25	X	X		X	X		X	X		X	X		X	X		X								
100	X	X		X	X		X	X		X	X		X	X										
200	X	X		X	X		X	X		X	X		X	X		X								
500	X	X		X	X		X	X		X	X		X	X		X			X			X		
1000	X	X		X	X		X	X		X	X		X	X										

	Western 0.8% Sulfur Coal						Anthra-cite			Lignite		
	Lime			Lime-stone			Lime			Lime		
Megawatts	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu	1.2 lbs SO_2/MM Btu	90% removal	0.5 lbs SO_2/MM Btu
25		X	X		X	X						
100												
200		X	X		X	X						
500		X	X		X	X	X	X		X	X	
1000												

Table 4-4. DESIGN PARAMETERS FOR THE FGD SYSTEMS

Model plant parameters for current NSPS	Characteristics and assumptions				
FGD systems	Lime	Limestone	Double alkali	Sodium solution	Magnesium oxide
Absorber type	TCA[1]	TCA	Tray	Tray	TCA
Number of stages	2	2	2	2	2
Liquid to gas ratio, L/G l/m^3 (gal/1000 acf)	5.3 (40)	8.7 (65)	2.7 (20)	1.2 (9)	5.3 (40)
Gas velocity in absorber, m/sec (ft/sec)	3.0 (10)	3.0 (10)	2.4 (8)	2.4 (8)	3.0 (10)
Flue gas temperature at absorber outlet, °C (°F)	52 (125)	52 (125)	52 (125)	52 (125)	52 (125)
Degree of reheat, °C (°F)	28 (50)	28 (50)	28 (50)	28 (50)	28 (50)
Hold tank retention time, min	10	10	6	1	10
Makeup requirement, %	-	-	5	5	7
Byproduct				H_2SO_4, Na_2SO_4	H_2SO_4

[1] Turbulent contact absorber

Table 4-4 (Cont'd). DESIGN PARAMETERS FOR THE FGD SYSTEMS

Model plant parameters for 90 % or greater control	Characteristics and assumptions				
FGD systems	Lime	Limestone	Double alkali	Sodium solution	Magnesium oxide
Absorber type	TCA	TCA	Tray	Tray	TCA
Number of stages	3	3	3	3	3
Liquid to gas ratio, L/G $1/m^3$ (gal/1000 acf)	8.0 (60)	11.3 (85)	4.0 (30)	1.6 (12)	8.0 (60)
Gas velocity in absorber, m/sec (ft/sec)	3.0 (10)	3.0 (10)	2.4 (8)	2.4 (8)	3.0 (10)
Flue gas temperature at absorber outlet, °C (°F)	52 (125)	52 (125)	52 (125)	52 (125)	52 (125)
Degree of reheat, °C (°F)	28 (50)	28 (50)	28 (50)	28 (50)	28 (50)
Hold tank retention time, min	10	10	6	1	10
Makeup requirement, %	-	-	5	5	7
Byproduct				H_2SO_4, Na_2SO_4	H_2SO_4

4.3 MODEL PLANT COSTS

A summary of the results of the cost analysis are presented in Table 4-5. These costs are in August 1980 dollars and include escalation through project completion. The escalation rate used was 7.5 percent per year.

The incremental cost of reducing the SO_2 emission standard from 516 ng/J (1.2 lbs/10^6 Btu) to 90 percent control varies with the sulfur content of the coal. For higher sulfur contents the impact is much less than for lower sulfur contents. For instance, the capital costs of a lime FGD system on a 500 MW boiler increases by only $0.83/kW for the 7 percent sulfur coal case, by $14.53/kW for the 3.5 percent sulfur case, and by $119.42/kW for the 0.8 percent sulfur case (assuming no FGD is required to meet the 516 ng/J level). Annual costs are similarly affected with costs increased by 0.19 mills/kWh for the 7.0 percent sulfur case, by 0.96 mills/kWh for the 3.5 percent sulfur case, and by 7.69 mills/kWh for the 0.8 percent sulfur case. The results also indicate the single plant application of combined coal cleaning and FGD is not economical. The only application where such a combination is feasible is when the use of FGD alone cannot produce compliance.

Comparing the 90 percent control case with the 215 ng/J (0.5 lb/10^6 Btu) case the capital costs of a lime FGD for a

Table 4-5. COSTS OF SO_2 CONTROL ALTERNATIVES

Case 1: 1.2 lbs/MMBtu

Coal type, % sulfur / Boiler capacity, megawatts	Lime FGD Capital $/kW	Lime FGD O & M	Lime FGD Fixed mills/kWh	Lime FGD Total	Limestone FGD Capital $/kW	Limestone FGD O & M	Limestone FGD Fixed mills/kWh	Limestone FGD Total	Mag-Ox FGD Capital $/kW	Mag-Ox FGD O & M	Mag-Ox FGD Fixed mills/kWh	Mag-Ox FGD Total	Double alkali FGD Capital $/kW	Double alkali FGD O & M	Double alkali FGD Fixed mills/kWh	Double alkali FGD Total	Wellman-Lord FGD Capital $/kW	Wellman-Lord FGD O & M	Wellman-Lord FGD Fixed mills/kWh	Wellman-Lord FGD Total
Eastern, 3.5																				
25	262.76	9.50	10.50	20.00	278.48	9.90	11.13	21.03	409.12	13.47	16.35	29.82	308.00	10.28	12.31	22.59	370.24	12.14	14.79	26.93
100	234.78	5.99	9.38	15.37	285.77	6.41	11.42	17.83	319.66	7.60	12.77	20.37	297.70	7.00	11.89	18.89	290.22	6.35	11.60	17.95
200	174.46	4.68	6.97	11.65	202.46	4.78	8.09	12.87	210.41	5.22	8.41	13.63	194.78	5.11	7.78	12.89	188.91	4.26	7.55	11.81
500	124.93	3.92	4.99	8.91	142.58	3.68	5.70	9.38	156.76	4.18	6.26	10.44	147.09	4.37	5.88	10.25	141.16	3.28	5.64	8.92
1000	103.71	3.34	4.14	7.48	119.02	3.28	4.76	8.04	131.00	3.53	5.23	8.76	119.60	3.72	4.78	8.50	116.05	2.68	4.64	7.32
Eastern, 7.0																				
25	321.08	11.58	12.83	24.41	338.64	12.00	13.53	25.53												
100	290.51	7.92	11.61	19.53	352.58	8.17	14.09	22.26												
200	217.36	6.41	8.68	15.09	252.11	6.30	10.07	16.37												
500	156.34	5.29	6.25	11.54	185.94	5.09	7.43	12.52												
1000	131.59	4.81	5.26	10.07	156.53	4.57	6.25	10.82												
Anthracite																				
500																				
Lignite																				
500	96.67	2.29	3.86	6.15																

Coal type, % sulfur / Boiler capacity, megawatts	Incremental boiler cost Capital $/kW	Incremental boiler cost O & M	Incremental boiler cost Fixed mills/kWh	Incremental boiler cost Total	Transportation Capital $/kW	Transportation O & M	Transportation Fixed mills/kWh	Transportation Total
Eastern, 0.8								
25	1.32		0.05	0.05				
200	0.58		0.02	0.02				
500	0.40		0.02	0.02				
Eastern, 3.5								
500								
Western, 0.8 (low rank)								
25	112.00		4.47	4.47				
200	48.75		1.95	1.95				
500	33.80		1.35	1.35				
Western, 0.8 (high rank)								
25	74.00		2.96	2.96				
200	32.15		1.28	1.28				
500	22.30		0.89	0.89				
Western								
Unspecified						17.88		17.88

Coal type, % sulfur / Boiler capacity, megawatts	Combination: Coal cleaning Capital $/kW	Coal cleaning O & M	Coal cleaning Fixed mills/kWh	Coal cleaning Total	Lime FGD Capital $/kW	Lime FGD O & M	Lime FGD Fixed mills/kWh	Lime FGD Total	Combination: Coal cleaning Capital $/kW	Coal cleaning O & M	Coal cleaning Fixed mills/kWh	Coal cleaning Total	Limestone FGD Capital $/kW	Limestone FGD O & M	Limestone FGD Fixed mills/kWh	Limestone FGD Total
Eastern, 3.5																
500	15.50	5.42	1.60	7.02	111.32	2.90	4.45	7.36	15.50	5.42	1.60	7.02	126.83	3.00	5.07	8.07

Table 4-5 (continued). COSTS OF SO_2 CONTROL ALTERNATIVES

Case 2: 90.0% SO_2 removal

Coal type, % sulfur	Lime FGD				Limestone FGD				Mag-Ox FGD				Double alkali FGD				Wellman-Lord FGD			
Boiler capacity, megawatts	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total
Eastern, 3.5																				
25	289.96	10.04	11.59	21.63	307.60	10.46	12.29	22.75	439.40	13.99	17.56	31.55	337.60	10.89	13.49	24.38	395.76	12.49	15.81	28.30
100	259.88	6.51	10.38	16.89	316.67	6.95	12.65	19.60	354.17	8.15	14.15	22.30	329.64	7.63	13.17	20.80	317.53	6.71	12.69	19.40
200	194.23	5.11	7.76	12.87	225.08	5.21	8.99	14.20	233.21	5.63	9.32	14.95	215.57	5.59	8.61	14.20	206.02	4.49	8.23	12.72
500	139.46	4.30	5.57	9.87	160.15	4.05	6.40	10.45	174.60	4.57	6.98	11.55	163.79	4.82	6.54	11.36	154.93	3.49	6.19	9.68
1000	115.91	3.67	4.63	8.30	134.06	3.61	5.36	8.97	146.93	3.85	5.87	9.72	133.76	4.09	5.34	9.43	127.56	2.84	5.10	7.94
Eastern, 7.0																				
25	322.48	11.67	12.88	24.55	339.88	12.06	13.50	25.64	481.56	15.40	19.24	34.64	374.92	12.78	19.98	27.76	417.48	12.85	16.68	29.53
100	291.52	7.98	11.65	19.63	353.70	8.23	14.13	22.36	398.03	9.26	15.90	25.16	364.41	9.32	14.56	23.88	336.49	6.93	13.44	20.37
200	218.09	6.47	8.71	15.18	252.70	6.35	10.10	16.35	264.99	6.76	10.59	17.35	242.43	7.16	9.69	16.85	220.93	4.67	8.83	13.50
500	157.17	5.45	6.28	11.73	186.59	5.15	7.46	12.61	205.81	5.75	8.22	13.97	183.80	6.47	7.34	13.81	169.24	3.79	6.76	10.55
1000	132.02	4.86	5.27	10.13	157.05	4.62	6.27	10.89	173.01	4.86	6.91	11.77	151.11	5.47	6.04	11.51	140.36	3.01	5.61	8.62
Western, 0.8																				
25	252.52	8.52	10.09	18.61	269.16	8.94	10.75	19.69												
200	166.09	3.85	6.64	10.49	192.13	4.12	7.68	11.80												
500	119.42	2.93	4.77	7.70	137.20	3.09	5.48	8.57												
Anthracite																				
500	116.57	2.82	4.66	7.48																
Lignite																				
500	116.71	2.86	4.66	7.52																

Case 3: 215 ng/J (0.5 lb/10^6 Btu)

Coal type, % sulfur	Lime FGD				Limestone FGD				Combination								Combination							
									Coal cleaning				Lime FGD				Coal cleaning				Limestone FGD			
Boiler capacity, megawatts	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total	Capital $/kW	O & M	Fixed mills/kWh	Total
Western, 0.8																								
25	226.68	8.08	9.06	17.14	241.76	8.46	9.66	18.12																
200	146.68	3.50	5.86	9.36	169.93	3.75	6.79	10.54																
500	105.44	2.66	4.21	6.87	119.95	2.79	4.79	7.58																
Eastern, 7.0																								
25									19.60	8.32	2.46	10.78	285.32	9.83	11.40	21.23	19.60	8.32	2.46	10.78	303.40	10.26	12.12	22.38
200									17.40	7.66	2.26	9.92	190.99	4.95	7.63	12.58	17.40	7.66	2.26	9.92	221.29	5.07	8.84	13.91
500									16.45	7.49	2.21	9.70	136.77	3.93	5.46	9.39	16.45	7.49	2.31	9.70	157.51	3.93	6.29	10.22

500 MW boiler burning 0.8 percent sulfur coal decrease by \$13.98/kW for the 215 ng/J case and annual costs decrease by 0.83 mills/kWh.

Appendix C presents sample detailed breakdowns of costs for the options evaluated.

The costs do not include SO_2 monitors that would be required for the revised NSPS. Based on EPA estimates such monitors would have a capital cost of about \$40,000 and an annualized cost of about \$12,000. The impacts of these costs are insignificant with the capital cost corresponding to \$1.60/kW on a 25 MW boiler down to \$0.04/kW on a 1000 MW boiler, and the annual costs corresponding to 0.08 mills/kWh on a 25 MW boiler down to 0.002 mills/kWh on a 1000 MW boiler.

4.4 ENERGY PENALTIES

Two types of energy penalties must be considered when emission control systems costs are calculated. Electrical power consumption by the emission control process reduces the net amount of power generated; and the control system's flue gas reheat and process heat requirements, depending upon plant design and operating characteristics, may reduce the plants net power production.

The additional power-generating capacity required to compensate for the power used by the emission control system evaluated is listed as a capacity penalty. This penalty is discussed in Subsection 4.4.1. Subsection 4.4.2 discusses the energy penalty which represents the increased number of Btu's required to produce a net kilowatt-hour of electricity. These penalties are expressed both as a percentage and as an additional operating cost in mills/kWh.

4.4.1 Emission System Capacity Penalties

Flue gas desulfurization systems cause losses in net generation by a power plant that sometimes require the addition of generation capacity. Factors that affect the cost of diverting a portion of a utility's electric generating capacity to supply the energy requirements of environmental control equipment or to replace lost capacity are listed below:

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

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

C. System capacity in MW.

D. Annual load growth of the system.

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

F. Reserve capacity requirement:

   1. Unit reliability by type of unit
   2. Unit reliability by size of unit
   3. Shape of load curve
   4. Mix of generating capacity
   5. Maintenance and overhaul

G. Capability of interconnections.

H. Potential for interchange purchases and sales:

   1. Short-term firm
   2. Economy transactions

I. Availability of unit participation.

J. Cost per kW of added generating capacity:

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

K. Cost and availability of fuels.

L. Load characteristics:

   1. Load factor
   2. Relative magnitude of monthly peak loads

M. Mix of generating plant capacity, present and future.

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

The costs presented in Section 4.3 do not include the costs of replacement capacity but do include the costs of purchased power which reflects the recovery of capital costs of generating units supplying the power. Values of the capacity losses due to the control options evaluated are presented in Table 4-6 expressed as a percentage of the plants gross generating capacity.

4.4.2 Emission System Energy Penalties

The energy penalties associated with flue gas desulfurization systems can very widely with the process and

Table 4-6. CAPACITY AND ENERGY PENALTIES ASSOCIATED WITH SO_2 CONTROL ALTERNATIVES EXPRESSED AS A PERCENTAGE OF GROSS OUTPUT

Case 1: 1.2 lb/MM Btu

Coal Type %, Sulfur	Capacity, MW	Lime		Limestone		Mag-Ox		Double alkali		Wellman-Lord	
		Capacity penalty	Energy penalty	Capacity penalty	Energy penalty	Capacity penalty	Energy penalty	Capacity penalty	Energy penalty	Capacity penalty	Energy penalty
Eastern, 3.5	25	3.03	4.67	3.03	4.67	3.80	5.44	3.03	4.67	3.80	9.16
	100	2.91	4.59	2.91	4.59	3.64	5.32	2.91	4.59	3.64	9.07
	200	2.76	4.41	2.76	4.41	3.45	5.10	2.76	4.41	3.45	8.81
	500	2.67	4.30	2.67	4.30	3.34	4.98	2.67	4.30	3.34	8.73
	1000	2.60	4.25	2.60	4.25	3.25	4.90	2.60	4.25	3.25	8.65
Eastern, 7.0	25	3.03	4.67	3.03	4.67						
	100	2.91	4.59	2.91	4.59						
	200	2.76	4.41	2.76	4.41						
	500	2.67	4.30	2.67	4.30						
	1000	2.60	4.25	2.60	4.25						
Eastern, 3.5 (with coal cleaning)	500	2.67	50.70	2.67	50.70						
Anthracite	500	2.67	4.30								
Lignite	500	2.67	4.30								

Table 4-6 (Continued).

Case 2 : 90%

Coal Type %, Sulfur	Capacity, MW	Lime		Limestone		Mag-Ox		Double alkali		Wellman-Lord	
		Capacity penalty	Energy penalty	Capacity penalty	Energy penalty	Capacity penalty	Energy penalty	Capacity penalty	Energy penalty	Capacity penalty	Energy penalty
Eastern, 3.5	25	3.03	4.67	3.03	4.67	3.80	5.44	3.03	4.67	3.80	9.72
	100	2.91	4.59	2.91	4.59	3.64	5.32	2.91	4.59	3.64	9.64
	200	2.76	4.41	2.76	4.41	3.45	5.10	2.76	4.41	3.45	9.41
	500	2.67	4.30	2.67	4.30	3.34	4.98	2.67	4.30	3.34	9.29
	1000	2.60	4.25	2.60	4.25	3.25	4.90	2.60	4.25	3.25	9.22
Eastern, 7.0	25	3.03	4.67	3.03	4.67	3.80	5.44	3.03	4.67	3.80	13.40
	100	2.91	4.59	2.91	4.59	3.64	5.32	2.91	4.59	3.64	13.24
	200	2.76	4.41	2.76	4.41	3.45	5.10	2.76	4.41	3.45	13.02
	500	2.67	4.30	2.67	4.30	3.34	4.98	2.67	4.30	3.34	12.90
	1000	2.60	4.25	2.60	4.25	3.25	4.90	2.60	4.25	3.25	12.83
Western, 8.0	25	3.03	4.67	3.03	4.67						
	200	2.76	4.41	2.76	4.41						
	500	2.67	4.30	2.67	4.30						
Anthracite	500	2.67	4.30								
Lignite	500	2.67	4.30								

Table 4-6 (Continued).

Case 3: 0.5 lb/MM Btu

Coal Type %, Sulfur	Capacity, MW	Lime		Limestone	
		Capacity penalty	Energy penalty	Capacity penalty	Energy penalty
Western, 0.8	25	3.03	4.67	3.03	4.67
	200	2.76	4.41	2.76	4.41
	500	2.67	4.30	2.67	4.30
Eastern, 7.0 (with coal cleaning)	25	3.03	10.67	3.03	10.67
	200	2.76	10.41	2.76	10.41
	500	2.67	10.30	2.67	10.30

vendor. In a sulfur dioxide scrubbing system, the scrubbing recurculation pumps and booster fans are the primary energy consumers. Different processes also require varying degrees of energy for scrubbing liquor makeup, scrubbing liquor regeneration, and sludge disposal. Additional penalties are caused by use of fuel or steam to reheat flue gases and steam to provide process steam in some of the regenerative systems. For this study, energy consumption by the electrical equipment, reheat system, and process heat is estimated for each of the cases evaluated. Table 4-6 also presents the energy penalty for each case as a percentage of gross electrical generation. Table 4-7 presents the energy penalty as an annualized charge in mills/kWh.

4.5 SLUDGE DISPOSAL ALTERNATIVES

Several methods are now used for disposal of scrubber sludge. The most common are ponding of untreated sludge and landfilling of treated and untreated sludge. An alternative to disposing of scrubber sludge is commercial utilization. This technique is practiced extensively in Japan, where scrubber sludges are oxidized to form the long fiber gypsum necessary for wallboard production. Although such techniques could be applicable in the United States if the economic incentives were adequate, at best they would account for only a minor fraction of sludge requiring disposal.

Table 4-7. ENERGY PENALTIES ASSOCIATED WITH SO_2 CONTROL ALTERNATIVES EXPRESSED IN MILLS PER KILOWATT HOUR

Case 1: 1.2 lb/MM Btu

Coal Type %, Sulfur	Capacity, MW	Lime Energy penalty	Limestone Energy penalty	Mag-Ox Energy penalty	Double alkali Energy penalty	Wellman-Lord Energy penalty
Eastern, 3.5	25	0.88	0.88	1.05	0.88	1.05
	100	0.84	0.84	1.01	0.82	1.01
	200	0.80	0.80	0.95	0.80	0.95
	500	0.77	0.77	0.92	0.77	0.92
	1000	0.75	0.75	0.90	0.75	0.90
Eastern, 7.0	25	0.88	0.88	1.05		
	100	0.84	0.84	1.01		
	200	0.80	0.80	0.95		
	500	0.77	0.77	0.92		
	1000	0.75	0.75	0.90		
Eastern, 3.5 (with coal cleaning)	500	12.68	12.68			
Anthracite	500	0.77				
Lignite	500	0.77				

Table 4-7 (Continued)

Case 2: 90%

Coal Type %, Sulfur	Capacity, MW	Energy penalty	Limestone Energy penalty	Mag-Ox Energy penalty	Double alkali Energy penalty	Wellman-Lord Energy penalty
Eastern, 3.5	25	0.97	0.97	1.16	0.97	1.16
	100	0.93	0.93	1.11	0.93	1.11
	200	0.88	0.88	1.05	0.88	1.05
	500	0.85	0.85	1.02	0.85	1.02
	1000	0.83	0.83	0.99	0.83	0.99
Eastern, 7.0	25	0.97	0.97	1.16	0.97	1.16
	100	0.93	0.93	1.11	0.93	1.11
	200	0.88	0.88	1.05	0.88	1.05
	500	0.85	0.85	1.02	0.85	1.02
	1000	0.83	0.83	0.99	0.83	0.99
Western, 0.8	25	1.16	1.16	1.39	1.16	1.39
	200	1.06	1.06	1.26	1.06	1.26
	500	1.02	1.02	1.22	1.02	1.22
Anthracite	500	0.85	0.85	1.02	0.85	1.02
Lignite	500	0.85	0.85	1.02	0.85	1.02

Table 4-7 (Continued).

Case 3: 0.5 lb/MM Btu

Coal Type %, Sulfur	Capacity, MW	Lime Energy penalty	Limestone Energy penalty
Western, 0.8	25	.97	.97
	200	.88	.88
	500	.85	.85
Eastern, 7.0 (with coal cleaning)	25	12.79	12.79
	200	12.71	12.71
	500	12.68	12.68

Ponding

Sludge disposal in a pond without providing environmental protection (such as chemical fixation or impervious liners) against seepage to water supplies constitutes a potential water quality hazard. The degree of hazard depends upon such site specific characteristics as topography, weather, soil characteristics, and proximity of ground and surface waters to the disposal site. In addition, there exist a significant number of other disposal variables (e.g., chemical constituents of the sludge and the condition of sludge disposal) that may impact the potential hazard posed by such a sludge pond.

Pond linings have been finding greater favor in recent years. Lining is an effective method to prevent groundwater contamination. On many areas, clay, concrete, wood or metal have been used as liners. Synthetic materials are finding increased use. These synthetic materials include polyvinyl chloride, rubber, synthetic rubber, polyethylene, propylene, and nylon. Since economics is a major factor, clay and synthetics will be the primary materials used for sludge liners. To be useful, liners must have long-life, endure temperature variations, and remain flexible. Several manufacturers offer acceptable liner materials.

Landfilling

The second method for disposal of scrubber sludges is use of either a dewatered or a stabilized ("fixed") sludge for landfill. Sludges can be dewatered by vacuum filtration or centrifugation to form a solid material that can be used for landfill. Since these dewatered sludges can reabsorb moisture and regain their original water content if untreated, chemical and physical stabilization or fixation processes are increasingly being used.

Chemical fixation of scrubber sludge is currently offered by several commercial groups including Dravo Corporation, I.U.C.S., Inc., Chicago Fly Ash, and The Chemfix Corporation. These commercial systems use fly ash, lime, silicates, and polyvalent metal ions (usually about 5 percent of the amount of sludge on a dry weight basis) to form a low-grade concrete. The product is a stable, inert material that will not release toxic metal ions or soluble species. It has sufficient strength to support buildings and will support vegetation.

The following factors affect the capital and annualized operating costs of sludge disposal:

1. Capital Cost

    a. Pond location
    b. Lining requirement
    c. Leachate monitoring

d. Overall size
e. Dewatering method

2. Annualized Operating Cost

a. Fixation chemicals
b. Utilities
c. Trucking

The split between capital and annual costs is not clearcut. For example, several firms will operate sludge disposal systems on a per ton basis. The utility will not be required to invest capital in the system. However, these contracts normally have "take or pay" clauses to protect the sludge disposal firm's capital investment. In essence, turn key disposal merely shifts the fixed charges of sludge disposal to direct operating expenses. In addition, pumping sludge instead of trucking sludge increases capital but reduces annual costs. Sluice lines and pumps are part of the capital costs borne by utility, while trucks to haul sludge are normally borne by trucking contractors. Another area which affects capital and annualized operating costs is dewatering. Horsepower requirements are reduced if ponding is used to dewater sludge instead of vacuum filtration or centrifugation. Capital costs increase however, since the pond must be larger and more complicated.

In this study, it was assumed that all sludge-generating FGD processes would dispose of the sludge in an on-site pond, lined with clay with the sludge stabilized by addition of fly ash and lime.

Table 4-8 identifies the annualized cost impact of various alternative subset conditions for sludge dipsosal for a new 500 MW plant burning high sulfur coal.

4.6 COST COMPARISONS FOR FGD SYSTEMS

The FGD system costs developed by PEDCo in this study were based on system parameters used at existing and planned installations and from control system manufacturers. The items of equipment required for each size and type of system were specified and vendor quotes obtained for these items. The quotes were obtained in mid-1976 and escalated using a 7.5 percent factor to future years.

In a report entitled "Detailed Costs Estimates for Advanced Effluent Desulfurization Processes" (EPA-600/2-75-006, Jan. 1975) costs for various FGD systems developed by the Tennessee Valley Authority (TVA) are presented. The costs presented in the document for a lime FGD system are compared to the estimates developed in this study.

The TVA costs reflect August 1974 prices and are escalated at 7.5 percent per year to 1980 to provide a common year for comparison. Table 4-9 presents a breakdown of the costs for a lime system on a 1000 MW boiler burning 3.5 percent sulfur coal and designed for 90 percent SO_2 removal.

As seen in the Table, the main areas of difference are the costs for the absorbers, reheaters, fans, and the indi-

Table 4-8. IMPACT OF VARIOUS SUBSET SLUDGE DISPOSAL OPTIONS ON THE ANNUALIZED COST OF SLUDGE DISPOSAL[a]

	Mills/kWh	$/Dry Ton	$/Wet Ton
Base Case	1.15	18.73	11.25
Synthetic Lining	0.37	6.03	3.62
Proprietary fixa-ation	0.15	2.44	1.46
Trucking - 5 miles	1.023	16.67	10.00
Trucking -10 miles	2.046	33.33	20.00
Trucking -15 miles	3.069	50.00	30.00
Pumping - 5 miles	0.224	3.65	2.19
Pumping -10 miles	0.336	5.47	3.28
Pumping -15 miles	0.448	7.30	4.38

[a] The various costs shown are additive to the "Base Case" cost which is a clay lined pond with fixation by addition of fly ash and lime.

Table 4-9. COMPARISON OF COSTS FOR A LIME FGD SYSTEM ON A 1000 MW NEW, COAL-FIRED GENERATING UNIT, 3.5% S COAL, AND 90% SO_2 REMOVAL

Capital Investment	TVA ($ million)[1]		PEDCo ($ million)
Cost item	1974	1980	1980
Lime receiving & storage	$ 1.228	$ 1.895	$ 1.684
Feed preparation	.586	0.904	1.140
Particulate & SO_2 scrubbers (4)	10.638	16.417	
SO_2 absorbers (8) (1 redun.)			45.444
Stack gas reheat	.955	1.474	6.212
Fans	1.161	1.792	3.604
Calcium solids disposal	5.018	7.744	4.626
Vacuum filters, fixation chemical storage			2.046
Utilities, service facilities, construction facilities & field expense, & contractor fee	5.021	7.749	5.489
Raw material inventory			.433
Engineering design & supervision	1.712	2.642	6.142
Contingency	1.926	2.972	18.296
Start up	2.260	3.488	3.296
Interest during construction(8%)	2.260	3.488	6.476(9%)
Field overhead			6.476
Freight			.768
Offsite expenses			1.943
Taxes			.921
Spares			.307
Land cost			.219
Total capital investment	$32.765	$50.565	$115.485

[1] Detailed Cost Estimates for Advanced Effluent Desulfurization Processes, prepared for Control System Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, under Interagency Agreement EPA IAG-134(d), Part A, by G.C. McGlamery, et al., Tennessee Valley Authority, pp. 244, 245. January 1975.

Table 4-9 (continued).

Annual Operating Costs	TVA ($ million)		PEDCo ($ million)
Raw Materials	1974	1980	1980
Lime	$3.2185	$4.9671	$ 6.223
Fixation chemicals			1.020
Utilities			
Steam	0.5684	0.8772	1.020
Process water	0.0374	0.0577	.063
Electricity	1.2895	1.9901	3.704
Labor			
Operating labor & supervision	0.2381	0.3675	0.453
Maintenance			
Labor & material	1.4978	2.3116	5.024
Supplies			0.754
Analyses	0.0595	0.0918	
Overhead			
Plant	0.7381	1.1391	3.116
Administrative	0.0238	0.0367	0.091
Sludge Handling			
Average capital costs	4.8820	7.5344	16.418
Depreciation			1.993
Taxes			7.780
Insurance			0.419
Total Operating Costs	$12.5531	$19.373	$49.098

rect charges and contingency. The reasons for the differentials are as follows:

1. TVA uses only 4 scrubbing trains to handle 1000 MW (250 MW per train). PEDCo uses 8 scrubbing trains (1 redundant module) to handle 1000 MW at 143 MW per train. The largest operational modules at the present time carry the equivalent of 150 to 160 MW of gas flow.

2. The TVA document specifies the year that base costs were obtained for absorbers, fans, and reheaters as 1971. These costs were then escalated to reflect 1974 costs. PEDCo base costs were obtained in 1976 and should therefore be more accurate.

3. TVA costs reflect minimum in-process storage with only pumps being spared. PEDCo costs include a spare scrubbing module with associated equipment, spare pumps, and excess inprocess storage capacity to obtain optimum operation.

4. TVA costs reflect disposal of untreated sludge in an on-site clay-lined pond. PEDCo's costs reflect the disposal of stabilized sludge in a clay-lined pond.

5. TVA costs reflect the use of venturi absorbers while PEDCo costs are for a Turbulent Contact Absorber (TCA).

6. TVA costs reflect an annual capacity factor of 80 percent for the boiler while PEDCo uses a 65 percent capacity factor. Over the 20 year life of an FGD, the 65 percent capacity factor would be more realistic.

7. TVA uses a contingency of 9 percent of direct costs while PEDCo uses 20 percent of direct and indirect costs. For the level of accuracy of the PEDCo estimates ($\pm$ 20%), a 20 percent contingency adheres to standard estimating criteria.

The nature of other variations in the cost estimates can not be determined based on available information. It should be noted that TVA is in the process of revising their cost estimates and preliminary results are much higher than in the 1975 document. Results were presented in a paper entitled "Economic Evaluation Techniques, Results, and Computer Modeling for Flue Gas Desulfurization," presented at the FGD Symposium sponsored by EPA in November, 1977. Comparative results for a limestone FGD on 3.5 percent sulfur coal meeting a 1.2 lb $SO_2/10^6$ Btu regulation for a 500 MW plant are presented in Table 4-10.

Table 4-10. COMPARISON OF COSTS FOR A LIMESTONE FGD SYSTEM ON A 500 MW NEW, COAL-FIRED GENERATING UNIT, 3.5% S COAL, AND 1.2 LBS/MILLION BTU ALLOWABLE EMISSIONS

Capital Investment Cost item	TVA ($ million) 1979	PEDCo ($ million) 1980
Limestone receiving & storage	$ 1.76	$ 1.22
Feed preparation	1.74	1.88
SO_2 scrubbers (4)	8.92	19.84
Stack gas reheat	1.28	3.10
Fans & ductwork	4.32	3.33
Calcium solids disposal	6.81	9.04
Utilities, service facilities, construction facilities & field expense, & contractor fee	6.20	3.21
Raw material inventory		0.15
Engineering design & supervision	1.21	3.08
Contingency	6.45	10.68
Start up	3.35	1.93
Interest during construction	4.65	3.84
Field overhead		3.84
Freight		0.39
Offsite expenses		1.15
Taxes		0.46
Spares		0.15
Land cost	1.03	0.14
Total capital investment	$47.71	$67.43

Table 4-10 (continued).

Annual Operating Costs

	TVA ($ million)	PEDCo ($ million)
Raw Materials	1979	1980
Limestone	$ 1.11	$ 1.08
Fixation chemicals		0.67
Utilities		
Steam	0.98	0.52
Process water	0.03	0.03
Electricity	1.64	1.90
Labor		
Operating labor & Supervision	0.33	0.34
Maintenance		
Labor & material	1.82	2.93
Supplies		0.44
Overhead		
Plant	1.11	1.86
Administrative	0.03	0.07
Sludge Handling		0.67
Average Capital Costs	7.00	9.47
Depreciation		4.49
Taxes		1.15
Insurance		0.24
Total Operating Costs	$14.11	$25.86

5.0 IMPACT OF EMISSION AVERAGING TIMES ON THE COSTS OF FGD

The specific time period over which emission test results are averaged to determine compliance has a significant impact on the selection and design of the control process. This is especially true in the case of SO_2 emission limitations. Coal is inherently variable when looking at the sulfur content. The sulfur occurs in veins as pyrites thus producing a nonhomogeneous condition when sulfur content is considered. This variability in sulfur content is very significant when looking at shorter averaging times over which a regulation must be met. The effect of shorter averaging times is an increase in the maximum sulfur content for which an FGD system must be designed.

Table 5-1 presents the sulfur variability in various coals over different averaging times for various size boilers. As can be seen the maximum sulfur content varies more for the smaller unit due to the smaller total amount of coal based over the averaging period. These values reflect a normal distribution of values as obtained by the sampling of unit trains. The relative standard deviations (RDS) are presented in Table 5-2.

Table 5-1. COAL ANALYSES AND SULFUR VARIABILITY OVER VARIOUS AVERAGING TIMES[1]

Coal type	Plant size, MW	Maximum average sulfur content, %				
		Long-term	Annual	30 days	1 day	3 hours
Eastern bituminous, 14% ash, 28,000 J/g (12,000 Btu/lb)	25	7.00	7.36	8.27	9.36	9.73
	500	7.00	7.23	7.79	8.88	9.23
	1000	7.00	7.22	7.75	8.78	9.19
Eastern bituminous, 14% ash, 28,000 J/g (12,000 Btu/lb)	25	3.50	3.68	4.13	4.68	4.86
	500	3.50	3.62	3.89	4.44	4.61
	1000	3.50	3.61	3.87	4.39	4.59
Western subbituminous 8% ash, 23,000 J/g (10,000 Btu/lb)	25	0.80	0.84	0.96	1.12	1.18
	500	0.80	0.83	0.90	1.05	1.10
	1000	0.80	0.83	0.89	1.03	1.09

[1] Distribution from unit train sampling.

Table 5-2. RELATIVE STANDARD DEVIATION OF SULFUR CONTENT IN COAL

Averaging Time	Boiler size 25 MW	500 MW	1000 MW
3 hr	0.237	0.194	0.190
24 hr	0.205	0.163	0.155
30 day	0.110	0.069	0.065
1 year	0.031	0.020	0.019
long term	0	0	0

The values in Table 5-1 were obtained by assuming a normal distribution of the values for the 7.0 and 3.5 percent sulfur coals and a log normal distribution for the 0.8 percent sulfur coal for a 95 percent confidence level.

For purposes of evaluating the cost impacts of various averaging times, a lime FGD system was costed for each of the maximum sulfur contents in Table 5-1. The FGD was designed for 90 percent SO_2 removal using design parameters as presented in Tables 4-1 and 4-4.

The results of this cost analysis are presented in Tables 5-3 through 5-6.

The results indicate that costs will increase as the averaging time is shortened. The effect is also more significant for smaller units due to the increased variability of sulfur as the quantity used during the averaging time

Table 5-3. COSTS OF A LIME FGD SYSTEM DESIGNED FOR

90 PERCENT SO_2 REMOVAL OVER AN ANNUAL AVERAGING PERIOD

1 Year 90% Control		Plant size					
Sulfur in coal		25 MW		500 MW		1000 MW	
		Capital, $/kW	Annual, mills/kWh	Capital, $/kW	Annual, mills/kWh	Capital $/kW	Annual, mills/kWh
	7.36%	296.10	23.51				
7.0%	7.23%			150.83	11.48		
	7.22%					126.56	9.92
	3.68%	271.40	20.90				
3.5%	3.62%			133.47	9.64		
	3.61%					111.41	8.13
	0.84%	243.24	18.25				
0.8%	0.83%			114.97	7.53		
	0.83%					97.17	6.39

Table 5-4. COSTS OF A LIME FGD SYSTEM DESIGNED FOR 90 PERCENT SO_2 REMOVAL OVER A 30-DAY AVERAGING PERIOD

30 Days 90% Control		Plant size					
Sulfur in coal		25 MW		500 MW		1000 MW	
		Capital, $/kW	Annual, mills/kWh	Capital, $/kW	Annual, mills/kWh	Capital $/kW	Annual, mills/kWh
	8.27%	307.34	23.96				
7.0%	7.79%			153.39	11.59		
	7.75%					128.34	9.99
	4.13%	278.32	21.17				
3.5%	3.89%			134.86	9.69		
	3.87%					112.47	8.17
	0.96%	246.68	18.39				
0.8%	0.90%			115.62	7.55		
	0.89%					97.58	6.40

Table 5-5. COSTS OF A LIME FGD SYSTEM DESIGNED FOR 90 PERCENT SO_2 REMOVAL OVER A 24-HOUR AVERAGING PERIOD

24 Hours 90% Control		Plant size					
Sulfur in coal		25 MW		500 MW		1000 MW	
		Capital, $/kW	Annual, mills/kWh	Capital, $/kW	Annual, mills/kWh	Capital $/kW	Annual, mills/kWh
7.0%	9.36% 8.88% 8.78%	319.92	24.47	157.05	11.73	131.56	10.12
3.5%	4.68% 4.44% 4.39%	287.06	21.52	137.66	9.81	114.63	8.26
0.8%	1.12% 1.05% 1.03%	250.84	18.55	115.72	7.56	98.51	6.44

Table 5-6. COSTS OF A LIME FGD SYSTEM DESIGNED FOR

90 PERCENT SO_2 REMOVAL OVER A 3-HOUR AVERAGING PERIOD

3 Hours 90% Control		Plant size					
Sulfur in coal		25 MW		500 MW		1000 MW	
		Capital, $/kW	Annual, mills/kWh	Capital, $/kW	Annual, mills/kWh	Capital $/kW	Annual, mills/kWh
7.0%	9.73%	322.48	24.55				
	9.23%			157.17	11.73		
	9.19%					132.02	10.13
3.5%	4.86%	289.96	21.63				
	4.61%			139.46	9.87		
	4.59%					115.91	8.30
0.8%	1.18%	252.52	18.61				
	1.10%			119.42	7.70		
	1.09%					98.86	6.45

decreases. For instance, reducing the averaging time for a 3.5 percent sulfur case from 1 year to 3 hours increases capital costs by 4.5 percent for the 500 MW case compared to 4.0 percent for the 1000 MW case. Also as the coal sulfur content decreases, the cost impacts of shorter averaging times increase. For the 0.8 percent sulfur case the differential capital costs between the 1 year and 3 hour averaging times varies from 3.9 percent for the 500 MW case to 1.7 for the 1000 MW case. Impacts on annual operating costs are not significant as annual operating costs reflect the annual average coal sulfur content.

6.0 SINGLE PLANT APPLICATIONS OF COMBINED PHYSICAL COAL CLEANING AND FLUE GAS DESULFURIZATION

Coal cleaning has the potential of being an economic method of reducing sulfur in coal by significant amounts. However the maximum removal obtainable with most coals with physical cleaning is around 40 percent. To meet stringent SO_2 emission levels on high sulfur coal would require additional SO_2 removal by an FGD system. In this analysis several cases were examined in order to evaluate any possible economic benefits obtainable by the use of coal cleaning in combination with FGD versus FGD alone. A single plant scenario was examined in which a single boiler is served by a coal cleaning plant and a lime or limestone FGD system is installed to meet the regulation level. In the first case, a 500 MW unit burning 3.5 percent sulfur coal and required to meet the 1.2 lb $SO_2/10^6$ Btu regulation was considered. Considered in the second case were boilers of 25, 200, and 500 MW burning 7.0 percent sulfur coal and required to meet a 215 ng/J (0.5 lb/10^6 Btu) regulation level. Table 6-1 presents the washability data for the two coals. The washability data were selected from "Sulfur Reduction Potential

Table 6-1. WASHABILITY DATA FOR HIGH SULFUR COALS

Washing gravity	Weight recovery, %	Heating value recovery, %	Heating value, J/g (Btu/lb)	Sulfur, %	Ash, %
1.3	21.9	26.3	32,900 (14,100)	1.32	2.6
1.3 x 1.4	62.5	73.1	32,000 (13,700)	1.66	5.3
1.4 x 1.6	82.4	93.4	31,000 (13,300)	1.97	8.2
1.6 x 1.9	85.9	96.3	30,600 (13,100)	2.09	9.2
Raw coal	100.0	100.0	28,000 (12,000)	3.48	14.0
1.3	52.2	59.8	32,700 (14,000	2.13	1.9
1.3 x 1.4	74.4	81.1	32,400 (13,900)	2.54	2.7
1.4 x 1.6	83.3	93.1	32,000 (13,700)	2.90	4.2
Raw coal	100.0	100.0	28,000 (12,000)	6.40	14.0

of U.S. Coals: A Revised Report of Investigations (EPA-600/2-76-091)," pages 71 and 164 as examples to use in the study cases.

Case 1 involves 40 percent removal of sulfur by coal washing of a 3.5 percent sulfur coal. Conventional coal preparation can be applied to many U.S. coals to achieve a 40 percent reduction in sulfur. In this situation, the model coal selected was an Illinois coal with a raw coal sulfur content of 3.48 percent. USBM washability data indicate that cleaning at 1.8 specific gravity (s.g.) would reduce the sulfur content by about 50 percent with a Btu yield of 93.4 percent; the data also indicate a 45 percent reduction in sulfur at 1.9 s.g. with a 96.3 percent Btu yield. Assuming that the higher cleaning gravity can be used, and that a grass roots cleaning plant is built, the capital costs of cleaning should be in the range of $10,000 to $30,000/ton per hour of raw coal processed. For a state of the art cleaning plant, operating 4000 hours/year and processing approximately 1,600,000 tons per year of raw coal, the capital investment is estimated to be approximately $3,500,000 to $8,300,000. Since the size of this cleaning plant is small, the cost is estimated on the high side of the range at $7,750,000 ($15.5/kW). Operating costs are estimated to be 2.85 to 4.30 mills/kWh. Additional coal required, due to Btu losses in the refuse, are estimated to be about 100,000 tons annually. At an assumed cost of $\$1.20/10^6$ Btu, the additional costs for coal would be $2,800,000 (0.98 mills/kWh).

Case 2 was evaluated in exactly the same manner as Case 1 using washability data for the 7.0 percent sulfur coal. Costs do not differ appreciably from those obtained for Case 1.

For the 1.2 lb $SO_2/10^6$ Btu regulation case, combined coal cleaning and lime or limestone FGD are more expensive than either lime or limestone FGD alone. Capital costs are about 1.5 percent higher, while annual costs are about 36 percent higher.

It appears that the only possible benefit from the use of combined coal cleaning and FGD is in cases where FGD alone cannot attain the level of control required.

APPENDIX A

DETAILED COST BREAKDOWNS

FOR PARTICULATE CONTROL DEVICES

The following sheets present detailed breakdowns for the cost estimates for ESP's, fabric filters, and venturi scrubbers. It should be noted however that the fixed costs shown in the breakdowns were not used in the cost estimates. Fixed costs in the estimates reflect 15.75 percent of the total capital investment.

500 MW 22 NG/J

NOV 7, 1977

ESP COST PROGRAM

CAPITAL INVESTMENT

DIRECT COSTS:		
ESP	4733000.	
DUCTING	1054000.	
DUST HANDLING	1016000.	
SUBTOTAL - DIRECT COSTS (INSTALLED)		6803000.
SLUDGE POND COST:		
LAND COST	0.	
POND PREPARATION COST	1406000.	
SUBTOTAL - SLUDGE DISPOSAL POND COSTS		1406000.

CAPITAL INVESTMENT (CONTD)

INDIRECT COSTS:

INTEREST DURING CONSTRUCTION	10% OF DIRECT AND SLUDGE POND COSTS	821000.	
FIELD OVERHEAD	10% OF DIRECT AND SLUDGE POND COSTS	821000.	
ENGINEERING	10% OF DIRECT COST	680000.	
FREIGHT	1.25% OF DIRECT COST	85000.	
OFFSITE	3% OF DIRECT COST	204000.	
TAXES	1.5% OF DIRECT COST	102000.	
SPARES	1% OF DIRECT COST	68000.	
ALLOWANCE FOR SHAKEDOWN	3% OF DIRECT COST	204000.	
	SUBTOTAL - INDIRECT COSTS		2985000.
	CONTINGENCY		2239000.
	CONTRACTOR FEE		672000.

	TOTAL CAPITAL INVESTMENT		14105000.
	CAPITAL INVESTMENT PER KW		28.21

500 MW 22 NG/J

NOV 7, 1977

ESP COST PROGRAM

OPERATING COST

	QUANTITY	RATE	ANNUAL COST,$
UTILITIES:			
ELECTRICITY	1285.KW	25.00MILLS/KWH	183000.
WATER	21.MG/HR	$ 0.20/MG	24000.
LABOR:			
DIRECT LABOR	12.0 MANHR/DAY	$ 9.00/MANHR	39000.
SUPERVISION	15% OF DIRECT LABOR		6000.
MAINTENANCE:			
LABOR AND MATERIAL	4.35% OF TOTAL CAPITAL INVESTMENT		614000.
SUPPLIES	15% OF LABOR AND MATERIALS		92000.
OVERHEAD:			
PLANT	50% OF OPERATING LABOR AND MAINTENANCE		375000.
PAYROLL	20% OF OPERATING LABOR		9000.
DUST DISPOSAL:	0.0 TON-MILE/YR	$ 0.00/TON-MILE	0.
		SUBTOTAL - OPERATION AND MAINTENANCE	1342000.

OPERATING COST (CONTD)

FIXED COST:			
DEPRECIATION		705000.	
INTERIM REPLACEMENT		49000.	
INSURANCE		42000.	
TAXES		564000.	
CAPITAL COST		1269000.	
	SUBTOTAL - FIXED COSTS		2629000.

	TOTAL ANNUAL COST		3971000.
	OPERATING COST PER KWH		1.39MILLS

CAPITAL INVESTMENT FOR FABRIC FILTERS

Regulation	13.4 ng/J		
Coal	0.8% S		
Size	500 MW		
<u>Direct Costs</u>			
Fabric Filter		10,890,628	
Ash handling		2,095,152	
Ducting		651,738	
Sub-total, Direct Costs			13,637,518
<u>Indirect Costs</u>			
@ 33.75%			4,602,662
Contingency	20% of Direct & Indirect		3,648,036
Grand Total			21,889,216
		$/KW	43.78

ANNUAL OPERATING COSTS - FABRIC FILTERS

<u>Utilities</u>	
Electricity	225,216
Water	16,617
Operating labor maintenance and bags	616,455
Overhead and administration	122,713
Fixed Cost @ 15.58%of total capital costs	4,979,569
Total Annual Costs	

JUL 22, 1977

W/VENTURI 500 MW,3.48% S,1.2 REG

INPUT

COST DATA

ESCF - 1.335	ELRT - 25.00 MILLS/KWH	WATRT - $ 0.200 /MGAL	RHRT - $ 0.000 /MMBTU
LABRT - $ 10.00 /MANHR	TAXRT - 0.000 %	CPTRT - 9.000 %	
LDRTE - $ 2000 /ACRE	SLTRR - $ 2.00 /TON-MILE		
LMRT - $ 50.00 /TON			

EXTRA FACTORS

EXF(58)= 0.800	EXF(59)= 0.800	EXF(60)= 0.800	EXF(77)= 0.800
EXF(78)= 0.800	EXF(**)= 0.000	EXF(**)= 0.000	EXF(**)= 0.000

PLANT DATA

NBLRP - 5	SLTRM - 1 MILES	ASHC - 14.000 %	SC - 3.480 %
HVC - 12000. BTU/LB	SO - 0.000 %	HVO - 0. BTU/GAL	FCCST - $ 0.
RTRLL - MODERATE			

BOILER 1

MCC - 125 MW	LIFE - 35 YEARS	DF - 0.170	SO2A - 1.20 LB/MMBTU
PART REMOVAL - YES	BACFM - 385000. ACFM	CF - 65 %	TEMP - 310.0 F
PARAL - 0.1 LB/MMBTU	EXPEF - 0.00 %	PEMF - 17	
FCO - 0. GAL/HR	FCT - 46. TON/HR		

BOILER 2

MCC - 125 MW	LIFE - 35 YEARS	DF - 0.170	SO2A - 1.20 LB/MMBTU
PART REMOVAL - YES	BACFM - 385000. ACFM	CF - 65 %	TEMP - 310.0 F
PARAL - 0.1 LB/MMBTU	EXPEF - 0.00 %	PEMF - 17	
FCO - 0. GAL/HR	FCT - 46. TON/HR		

BOILER 3

MCC - 125 MW	LIFE - 35 YEARS	DF - 0.170	SO2A - 1.20 LB/MMBTU

PART REMOVAL - YES	BACFM - 385000. ACFM	CF - 65 %	TEMP - 310.0 F
PARAL - 0.1 LB/MMBTU	EXPEF - 0.00 %	PEMF - 17	
FCO - 0. GAL/HR	FCT - 46. TON/HR		

BOILER 4

MCC - 125 MW	LIFE - 35 YEARS	DF - 0.170	SO2A - 1.20 LB/MMBTU
PART REMOVAL - YES	BACFM - 385000. ACFM	CF - 65 %	TEMP - 310.0 F
PARAL - 0.1 LB/MMBTU	EXPEF - 0.00 %	PEMF - 17	
FCO - 0. GAL/HR	FCT - 46. TON/HR		

BOILER 5

MCC - 0 MW	LIFE - 35 YEARS	DF - 0.170	SO2A - 1.20 LB/MMBTU
PART REMOVAL - YES	BACFM - 385000. ACFM	CF - 65 %	TEMP - 310.0 F
PARAL - 0.1 LB/MMBTU	EXPEF - 0.00 %	PEMF - 17	
FCO - 0. GAL/HR	FCT - 0. TON/HR		

SYSTEM ASSUMPTIONS

- A COMMON FGD SCRUBBING SYSTEM IS ASSUMED FOR THE BOILERS. FLUE GAS FLOWS FROM THE BOILERS ARE COMBINED IN A COMMON HEADER BEFORE THE SCRUBBING TRAINS. THE SCRUBBING TRAINS ARE SIZED TO HANDLE THE TOTAL GAS FLOW.

- THE PROGRAM COST BASIS IS AUGUST 1976. AN ESCALATION FACTOR OF 1.335 IS USED TO UPDATE THE COSTS.

- THE FIXED CHARGES ARE CALCULATED BY USING THE FOSTER PROCEDURE OF ANNUALIZING THE CAPITAL INVESTMENT.

- NO ON SITE ASH/SLUDGE DISPOSAL AREA IS AVAILABLE. COSTS OF TRUCKING ASH/SLUDGE TO A SITE 1 MILES AWAY ARE INCLUDED IN THE OPERATING COSTS.

LIME FGD

CAPITAL INVESTMENT

W/VENTURI 500 MW,3.48% S,1.2 REG

		EQUIPMENT COST, $
LIME PREPARATION		
CONVEYORS	508000.	
SLAKERS AND PUMPS	127000.	
STORAGE SILOS	856000.	
STORAGE TANKS	210000.	
PUMPS AND MOTORS	32000.	
	SUB TOTAL - LIME PREP	1733000.
SO2 SCRUBBING		
ABSORBERS	13938000.	
FANS AND MOTORS	2174000.	
HEAT EXCHANGERS	3100000.	
SOOT BLOWERS	3189000.	
VALVES AND DUCTING	1617000.	
HOLD TANKS	880000.	
PUMPS AND MOTORS	1988000.	
	SUB TOTAL - SO2 SCRUB	26886000.
PARTICULATE SCRUBBING		
VENTURI SCRUBBERS	9570000.	
HOLD TANKS	626000.	
PUMPS AND MOTORS	1988000.	
	SUB TOTAL - PART SCRUB	12184000.

CAPITAL INVESTMENT (CONTD)

SLUDGE DISPOSAL

CLARIFIERS	1092000.	
VACUUM FILTERS	1708000.	
CHEMICAL STORAGE	51000.	
MOBILE EQUIPMENT	68000.	
TANKS AND AGITATORS	97000.	
PUMPS AND MOTORS	104000.	
SUB TOTAL - SLUDGE DISP		3120000.
TOTAL INSTALLED COST		43923000.
RAW MATL INVENTORY		195000.
SLUDGE POND		3048000.

CAPITAL INVESTMENT (CONTD)

INDIRECT COSTS

INTEREST DURING CONSTRUCTION	4697000.	
FIELD OVERHEAD	4697000.	
ENGINEERING	4392000.	
FREIGHT	549000.	
OFFSITE	1409000.	
TAXES	659000.	
SPARES	220000.	
ALLOWANCE FOR SHAKEDOWN	2358000.	
TOTAL INDIRECT COST		18981000.
CONTINGENCY		13229000.
CONTRACTOR FEE		3969000.
LAND COST		188000.
TOTAL CAPITAL INVESTMENT		83533000.
TOTAL INVESTMENT PER KW		167.07

LIME FGD

OPERATING COST

W/VENTURI 500 MW,3.48% S,1.2 REG

	QUANTITY	RATE	ANNUAL COST, $
RAW MATERIAL			
LIME	9.8 TON/HR	$ 50.00 /TON	2798000.
FIXATION CHEMICAL	7.7 TON/HR	$ 20.00 /TON	878000.
UTILITIES			
WATER	641.2 GPM	$ 0.200 /MGAL	35000.
ELECTRICITY	16711.6 KW	25.00 MILLS/KWH	1903000.
REHEAT	92.0 MMBTU/HR	$ 1.25 /MMBTU	524000.
LABOR			
DIRECT LABOR	76.00 MANHR/DAY	$ 10.00 /MANHR	277000.
SUPERVISION	15 % OF DIRECT LABOR		42000.
MAINTENANCE			
LABOR AND MATERIAL	4.35 % OF TOTAL CAPITAL INVEST		3634000.
SUPPLIES	15 % OF LABOR AND MATERIAL		545000.
OVERHEAD			
PLANT	50 % OF OPERATING LABOR AND MAINT		2249000.
PAYROLL	20 % OF OPERATING LABOR		64000.
SLUDGE HANDLING	439000. TON-MILE/YR	$ 2.00 /TON-MILE	878000.

SUB TOTAL - OPERATION AND MAINTENANCE 13827000.

OPERATING COST (CONTD)

	ANNUAL COST, $	
FIXED CHARGES		
DEPRECIATION	1429000.	
TAXES	5578000.	
INSURANCE	300000.	
CAPITAL COSTS	11772000.	
SUB TOTAL - FIXED CHARGES		19079000.
TOTAL ANNUAL COST		32906000.
OPERATING COST PER KWH		11.55 MILLS

// XEQ FGDR2

APPENDIX B

COST IMPLICATIONS OF ADDING SPARE

MODULES TO FLUE GAS DESULFURIZATION SYSTEMS

COST IMPLICATIONS OF ADDING SPARE MODULES TO FLUE GAS DESULFURIZATION SYSTEMS

In reviewing air pollutant emission limitations, an important consideration is the time period over which a certain limitation must be attained. This directly affects the required operational availability of pollutant control systems. One system of major concern is flue gas desulfurization (FGD). The basic approach to increasing the availability of FGD systems is to install a spare scrubbing module, but this will have a definite cost impact on the system.

The purpose of installing a spare module is to increase the availability of the FGD system. The percent availability is a ratio of scrubber operating time divided by boiler operating time. The availability for small boilers with one original module and one spare module is 99%, assuming an availability of 90% for each module. As boiler size increases to a point where it is necessary to have two or more original modules, availability decreases. This is explained by the fact that there is only one spare module that can operate while two or more original modules are out of operation. Table 1 presents the effect on availability of adding a spare module to various size FGD systems based on assumed availabilities of 0.90 for a single module and 100 percent availability of a boiler.

Table 1. PERCENT AVAILABILITY

MW	Availability Limestone	Wellman-Lord
25	0.99	0.99
50	0.99	0.99
100	0.99	0.99
200	0.97	0.97
350	0.95	0.95
500	0.92	0.92
750	0.89	0.89
1000	0.82	0.82

In order to determine the additional cost incurred by adding a spare module to a new lime or Wellman-Lord FGD system, PEDCo's cost estimating procedure was utilized.

First, capital and annual costs were estimated for both FGD systems applied to seven predetermined boiler sizes. Input for all the boilers was kept the same except for size-related factors such as ACFM and fuel consumption. The costs are based on burning a typical high sulfur coal (10% ash, 3.5% S, and 11,000 Btu/lb). In each case, the allowable SO_2 emission level is 1.2 lb/10^6 Btu. All input data and assumptions are listed in Table 2.

Costs were then estimated for each size boiler for each type FGD system with one spare scrubbing module. All other

Table 2. DATA AND ASSUMPTIONS

Rate data	FGD chemical cost, dollars/ton
Escalation factor - 1.335[a]	Lime - 40.00
Electricity, mills/kWh - 20.00	Soda ash - 65.00
Water, dollars/1000 gal - 0.20	Salt cake - 30.00
Labor, dollars/man-hr - 10.00	Sulfur acid - 20.00
Capital charge, percent - 9.00	
Land, dollars/acre - 2000.00	

Boiler data	Fuel analysis
Life, years - 35	Ash content of coal, % - 11.0
Duct factor - .17	Coal sulfur content, % - 3.5
Allowable SO_2, lb/10^6 Btu - 1.2	Coal heating value, lb/10^6 Btu - 11,000

[a] August 1980.

factors were kept constant. It was assumed that the spare module is of the same size as the required modules (i.e., for a 50 MW boiler with one FGD module the spare is sized to handle 50 MW; for a 500 MW boiler with four FGD modules, corresponding to 125 MW each, the spare is sized to handle 125 MW). Costs obtained for the system with a spare module were then compared to the base case costs.

Table 3 presents the percent increase in capital cost that can be expected when a spare module is installed. Figures 1 through 4 graphically illustrate capital cost trends with and without spare modules. Generally speaking, the percent increase for a small boiler is high compared to a larger one. This is because a small boiler only needs one module to operate properly. By adding another module, the capital cost will almost double, whereas a larger boiler with more than one module to begin with would not experience such a drastic increase. Table 4 presents the percent increase in annual costs that results from installation of a spare module. Figures 5 and 6 illustrate the added operating expense per kWh when a spare module is incorporated into a Wellman-Lord process or a lime scrubbing FGD. Operating costs per kWh is calculated by dividing the total annual cost by kWh's of electricity generated per year. The annual cost itself is the sum of fixed charges which are a certain

Table 3. CAPITAL COST EFFECTS OF ADDING A REDUNDANT ABSORBER TO A LIME AND WELLMAN-LORD FGD SYSTEM

Boiler capacity, MW	Lime, percent increase	Wellman-Lord, percent increase
25	56.3	50.6
50	60.9	55.7
100	65.3	61.8
200	36.4	37.8
350	25.7	24.6
500	19.6	20.4
750	16.1	15.8

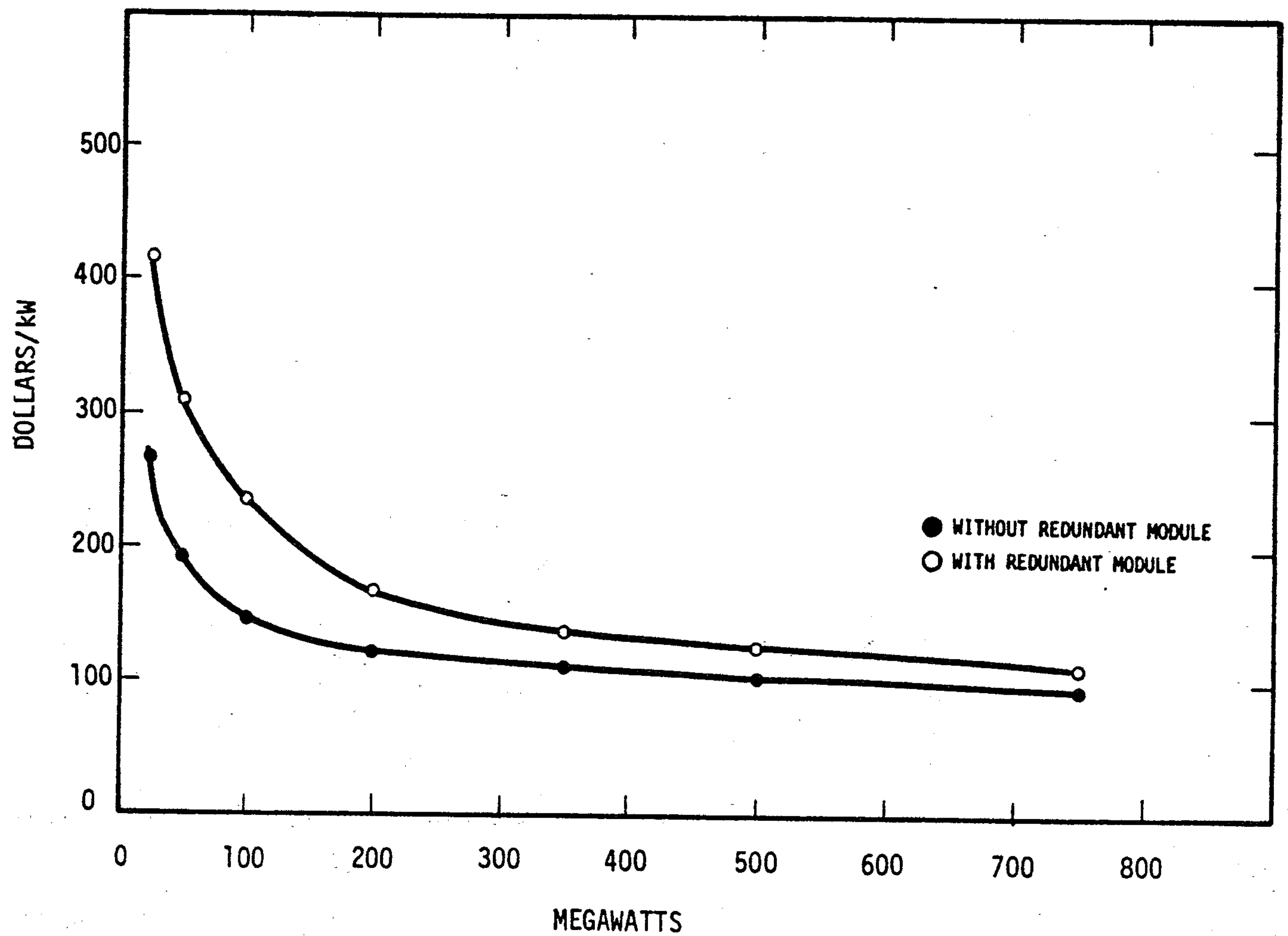

Figure 1. Reflected increase in capital cost per kilowatt through the addition of one redundant module for lime scrubbing.

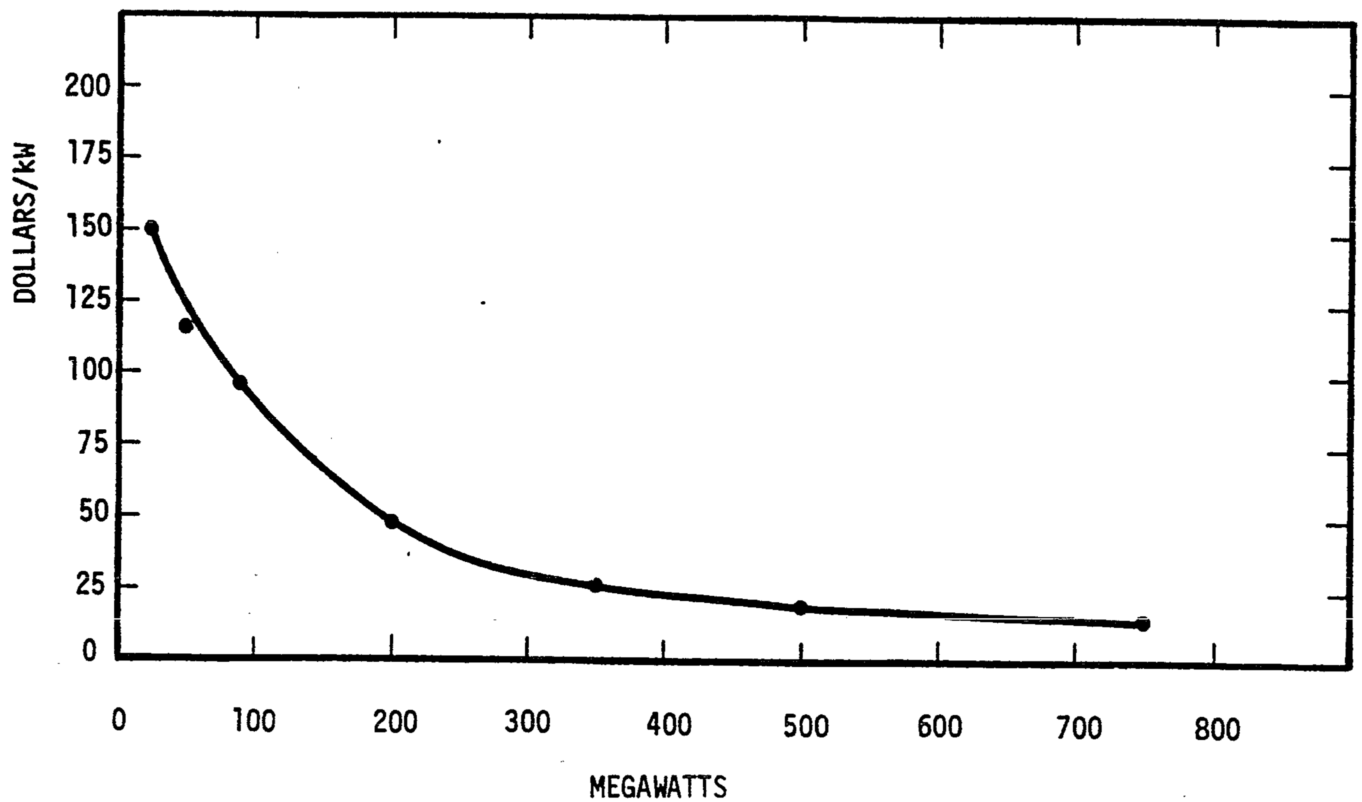

Figure 2. Actual capital cost increase per kilowatt by the addition of one redundant module for lime scrubbing.

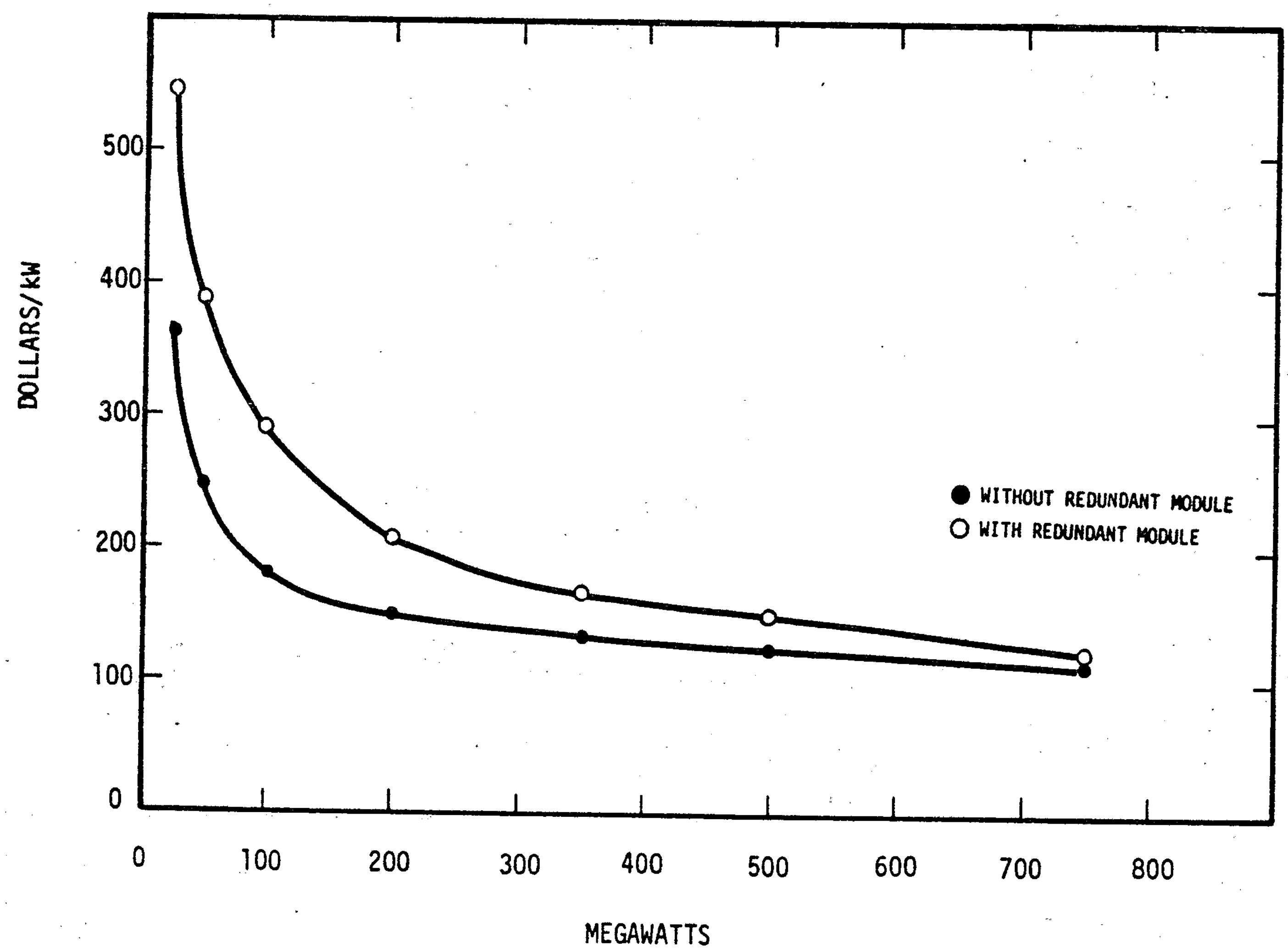

Figure 3. Reflected increase in capital cost per kilowatt through the addition of one redundant module for the Wellman-Lord process.

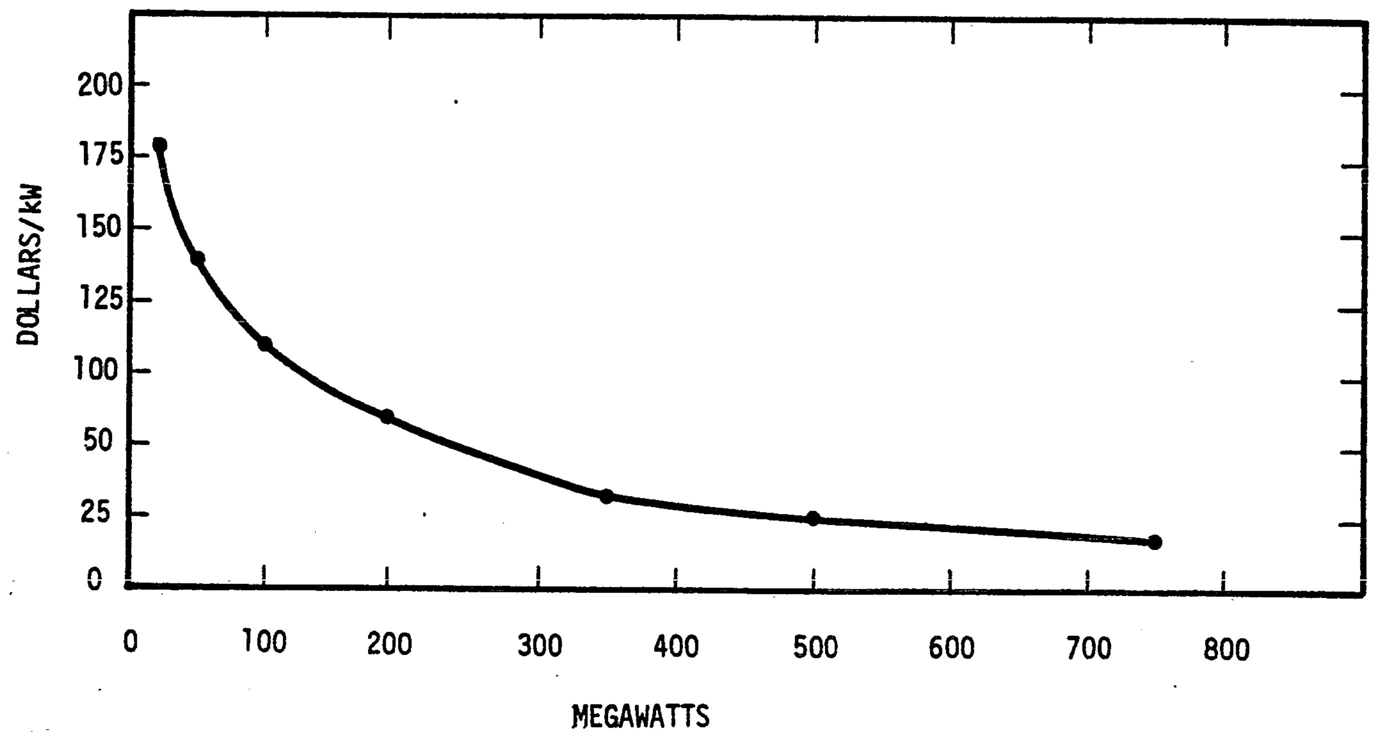

Figure 4. Actual capital cost increase per kilowatt by the addition of one redundant module for the Wellman-Lord process.

Table 4. ANNUAL COST EFFECTS OF ADDING A REDUNDANT MODULE TO LIME AND WELLMAN-LORD FGD SYSTEMS

Boiler capacity, MW	Lime, % increase	Wellman-Lord, % increase
25	40.0	42.3
50	53.7	47.1
100	55.5	52.5
200	32.7	35.0
350	23.7	23.0
500	18.0	20.1
750	14.3	12.5

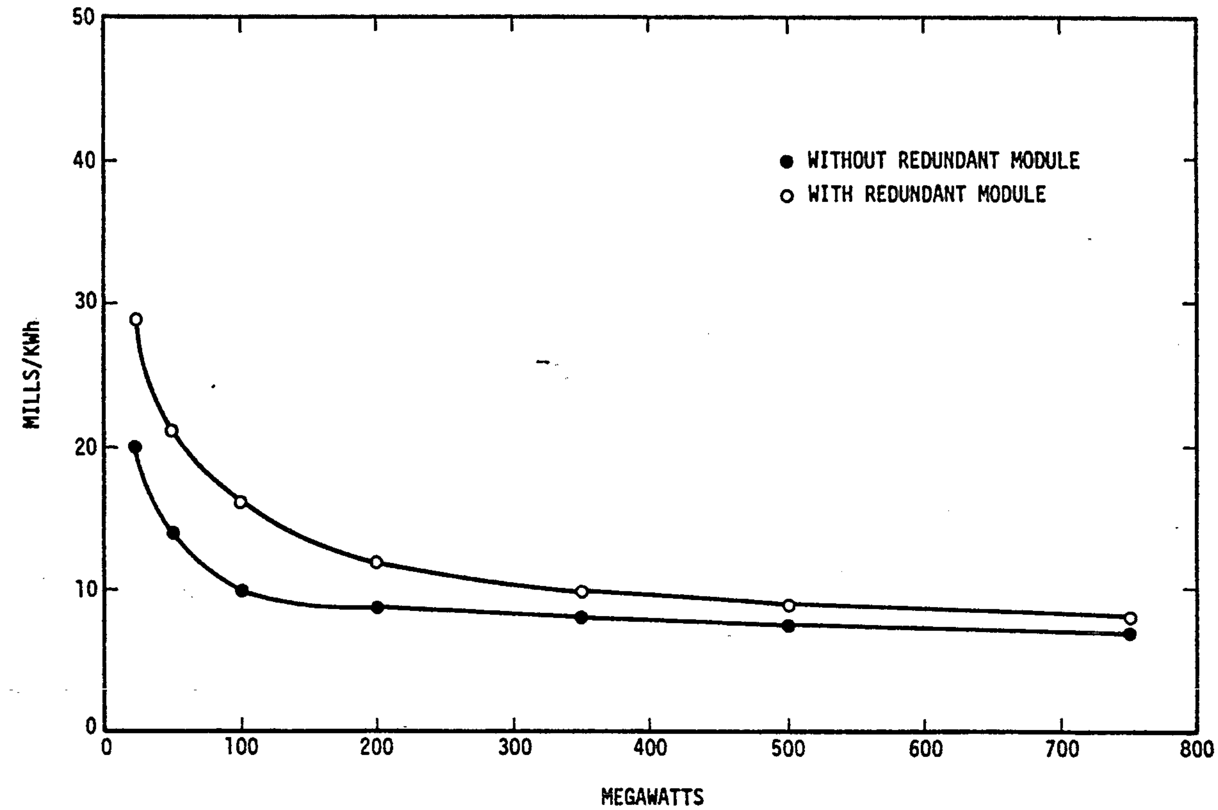

Figure 5. Reflected increase in annual cost per kilowatt-hour through the addition of one redundant module for lime scrubbing.

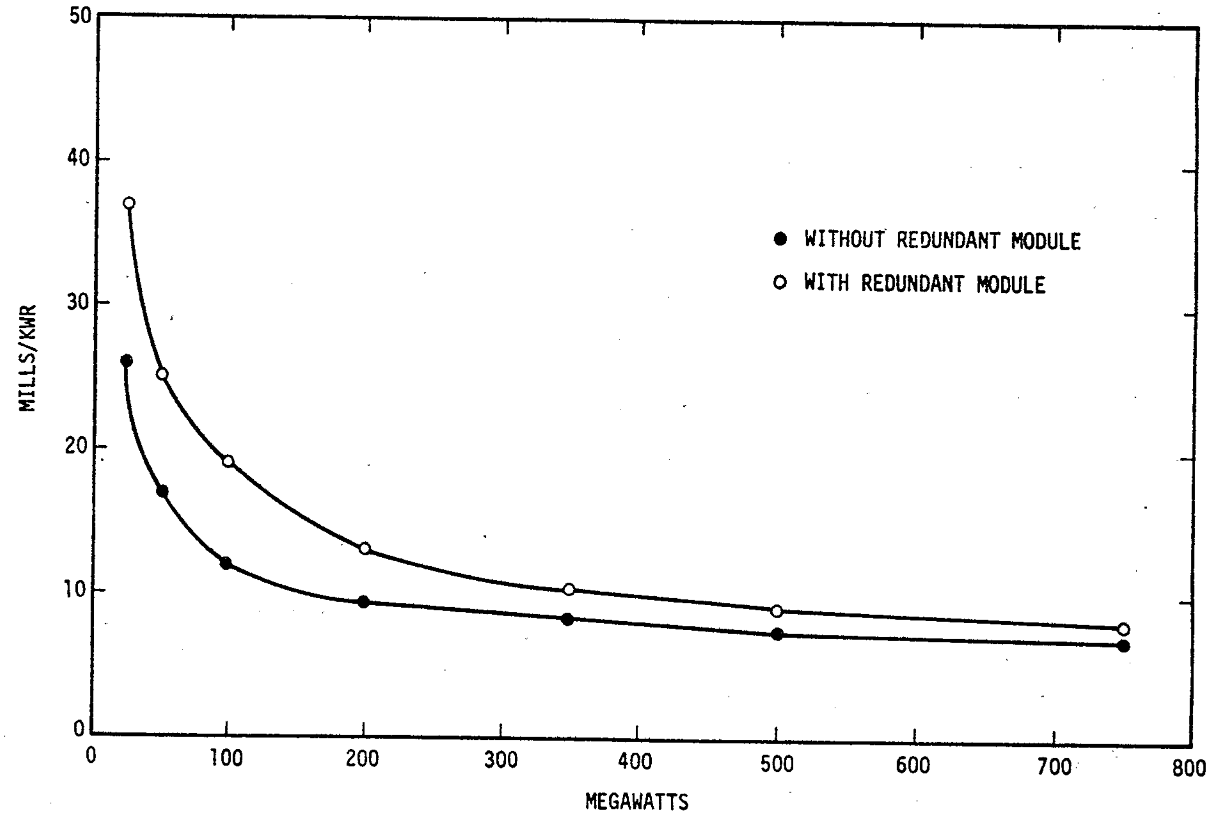

Figure 6. Reflected increase in annual cost per kilowatt-hour through the addition of one redundant module for the Wellman-Lord process.

percentage of total capital cost, plus operation and maintenance cost. For the Wellman-Lord process another factor considered in the operating cost per kWh is the by product credit since substances are produced. Comparing effects of spare modules on capital cost versus effects on annual costs, it can be seen that there is less of an impact on annual costs.

APPENDIX C

DETAILED COST BREAKDOWNS FOR FGD SYSTEMS

The following sheets present example breakdowns of costs for the FGD systems evaluated in this study. Samples included are a lime FGD on a 500 MW boiler burning 3.5 percent sulfur coal and having 90 percent efficiency, a lime FGD on a 500 MW boiler burning low sulfur (0.8%) coal and having 90 percent efficiency, and a magnesium oxide FGD on a 500 MW boiler burning 3.5 percent sulfur coal and having 90 percent efficiency.

INPUT

```
COST DATA
   ESCF  -  1.335                 ELRT - 25.00 MILLS/KWH       WATRT - $ 0.200 /MGAL       RHRT - $ 1.250 /MMBTU
   LABRT - $ 10.00 /MANHR         TAXRT -  0.000 %             CPTRT -  9.000 %
   LORTE - $ 2000 /ACRE           SLTRR - $ 2.00 /TON-MILE
   LMRT  - $ 50.00 /TON

EXTRA FACTORS
   EXF( 6)= 1.146                 EXF( 7)= 1.104               EXF(11)= 1.178              EXF(12)= 1.500
   EXF(17)= 0.000                 EXF(21)= 2.500               EXF(23)= 2.960              EXF(58)= 0.800
   EXF(59)= 0.600                 EXF(60)= 0.800               EXF(77)= 0.800              EXF(**)= 0.000

PLANT DATA
   NBLRP -  5                     SLTRM -  1 MILES             ASHC - 14.000 %             SC -  4.600 %
   HVC - 12000. BTU/LB            SO -  0.000 %                HVO -      0. BTU/GAL       FCCST - $       0.
   RTRLL - MODERATE

BOILER  1
   MCC -  125 MW                  LIFE - 35 YEARS              DF - 0.170                  SO2A - 0.55 LB/MMBTU
   PART REMOVAL - NO              BACFM -  385000. ACFM        CF - 65 %                   TEMP - 310.0 F
   FCO -       0. GAL/HR          FCT -   46. TON/HR

BOILER  2
   MCC -  125 MW                  LIFE - 35 YEARS              DF - 0.170                  SO2A - 0.55 LB/MMBTU
   PART REMOVAL - NO              BACFM -  385000. ACFM        CF - 65 %                   TEMP - 310.0 F
   FCO -       0. GAL/HR          FCT -   46. TON/HR

BOILER  3
   MCC -  125 MW                  LIFE - 35 YEARS              DF - 0.170                  SO2A - 0.55 LB/MMBTU
   PART REMOVAL - NO              BACFM -  385000. ACFM        CF - 65 %                   TEMP - 310.0 F
```

FCO - 0. GAL/HR FCT - 46. TON/HR

BOILER 4

MCC - 125 MW	LIFE - 35 YEARS	DF - 0.170	SO2A - 0.55 LB/MMBTU
PART REMOVAL - NO	BACFM - 385000. ACFM	CF - 65 %	TEMP - 310.0 F
FCO - 0. GAL/HR	FCT - 46. TON/HR		

BOILER 5

MCC - 0 MW	LIFE - 35 YEARS	DF - 0.170	SO2A - 0.55 LB/MMBTU
PART REMOVAL - NO	BACFM - 385000. ACFM	CF - 65 %	TEMP - 310.0 F
FCO - 0. GAL/HR	FCT - 0. TON/HR		

SYSTEM ASSUMPTIONS

- A COMMON FGD SCRUBBING SYSTEM IS ASSUMED FOR THE BOILERS. FLUE GAS FLOWS FROM THE BOILERS ARE COMBINED IN A COMMON HEADER BEFORE THE SCRUBBING TRAINS. THE SCRUBBING TRAINS ARE SIZED TO HANDLE THE TOTAL GAS FLOW.

- THE PROGRAM COST BASIS IS AUGUST 1976. AN ESCALATION FACTOR OF 1.335 IS USED TO UPDATE THE COSTS.

- THE FIXED CHARGES ARE CALCULATED BY USING THE FOSTER PROCEDURE OF ANNUALIZING THE CAPITAL INVESTMENT.

- NO ON SITE ASH/SLUDGE DISPOSAL AREA IS AVAILABLE. COSTS OF TRUCKING ASH/SLUDGE TO A SITE 1 MILES AWAY ARE INCLUDED IN THE OPERATING COSTS.

LIME FGD

CAPITAL INVESTMENT

500 MW, 3.48% S, 90% REG

	EQUIPMENT COST, $	
LIME PREPARATION		
CONVEYORS	546000.	
SLAKERS AND PUMPS	161000.	
STORAGE SILOS	1249000.	
STORAGE TANKS	261000.	
PUMPS AND MOTORS	36000.	
	SUB TOTAL - LIME PREP	2253000.
SO2 SCRUBBING		
ABSORBERS	15973000.	
FANS AND MOTORS	2040000.	
HEAT EXCHANGERS	3100000.	
SOOT BLOWERS	1196000.	
VALVES AND DUCTING	1617000.	
HOLD TANKS	1037000.	
PUMPS AND MOTORS	2982000.	
	SUB TOTAL - SO2 SCRUB	27945000.

CAPITAL INVESTMENT (CONTD)

SLUDGE DISPOSAL

CLARIFIERS	986000.	
VACUUM FILTERS	0.	
CHEMICAL STORAGE	44000.	
MOBILE EQUIPMENT	62000.	
TANKS AND AGITATORS	95000.	
PUMPS AND MOTORS	245000.	
SUB TOTAL - SLUDGE DISP		1432000.
TOTAL INSTALLED COST		31630000.
RAW MATL INVENTORY		304000.
SLUDGE POND		7986000.

CAPITAL INVESTMENT (CONTD)

INDIRECT COSTS

INTEREST DURING CONSTRUCTION	3962000.	
FIELD OVERHEAD	3962000.	
ENGINEERING	3163000.	
FREIGHT	395000.	
OFFSITE	1188000.	
TAXES	474000.	
SPARES	158000.	
ALLOWANCE FOR SHAKEDOWN	1996000.	
TOTAL INDIRECT COST		15298000.
CONTINGENCY		11044000.
CONTRACTOR FEE		3313000.
LAND COST		154000.
TOTAL CAPITAL INVESTMENT		69729000.
TOTAL INVESTMENT PER KW		139.46

LIME FGD

OPERATING COST

500 MW,3.48% S,90% REG

	QUANTITY	RATE	ANNUAL COST, $
RAW MATERIAL			
LIME	11.3 TON/HR	$ 50.00 /TON	3219000.
FIXATION CHEMICAL	4.6 TON/HR	$ 20.00 /TON	527000.
UTILITIES			
WATER	591.9 GPM	$ 0.200 /MGAL	32000.
ELECTRICITY	16711.6 KW	25.00 MILLS/KWH	1903000.
REHEAT	92.0 MMBTU/HR	$ 1.25 /MMBTU	524000.
LABOR			
DIRECT LABOR	76.00 MANHR/DAY	$ 10.00 /MANHR	277000.
SUPERVISION	15 % OF DIRECT LABOR		42000.
MAINTENANCE			
LABOR AND MATERIAL	4.35 % OF TOTAL CAPITAL INVEST		2889000.
SUPPLIES	15 % OF LABOR AND MATERIAL		433000.
OVERHEAD			
PLANT	50 % OF OPERATING LABOR AND MAINT		1821000.
PAYROLL	20 % OF OPERATING LABOR		64000.
SLUDGE HANDLING	264000. TON-MILE/YR	$ 2.00 /TON-MILE	528000.

SUB TOTAL - OPERATION AND MAINTENANCE 12259000.

OPERATING COST (CONTD)

	ANNUAL COST, $	
FIXED CHARGES		
DEPRECIATION	1206000.	
TAXES	4708000.	
INSURANCE	253000.	
CAPITAL COSTS	9936000.	
SUB TOTAL - FIXED CHARGES		16103000.

LIME FGD

CAPITAL INVESTMENT

500 MW,LOW'S',W.HIGH BTU,90% REG

	EQUIPMENT COST, $	
LIME PREPARATION		
CONVEYORS	471000.	
SLAKERS AND PUMPS	82000.	
STORAGE SILOS	486000.	
STORAGE TANKS	143000.	
PUMPS AND MOTORS	28000.	
	SUB TOTAL - LIME PREP	1210000.
SO2 SCRUBBING		
ABSORBERS	15973000.	
FANS AND MOTORS	2040000.	
HEAT EXCHANGERS	3100000.	
SOOT BLOWERS	1196000.	
VALVES AND DUCTING	1617000.	
HOLD TANKS	1037000.	
PUMPS AND MOTORS	2982000.	
	SUB TOTAL - SO2 SCRUB	27945000.

CAPITAL INVESTMENT (CONTD)

SLUDGE DISPOSAL

CLARIFIERS	530000.	
VACUUM FILTERS	0.	
CHEMICAL STORAGE	18000.	
MOBILE EQUIPMENT	42000.	
TANKS AND AGITATORS	87000.	
PUMPS AND MOTORS	203000.	
SUB TOTAL - SLUDGE DISP		880000.
TOTAL INSTALLED COST		30035000.
RAW MATL INVENTORY		70000.
SLUDGE POND		3793000.

CAPITAL INVESTMENT (CONTD)

INDIRECT COSTS

INTEREST DURING CONSTRUCTION	3383000.	
FIELD OVERHEAD	3383000.	
ENGINEERING	3004000.	
FREIGHT	375000.	
OFFSITE	1015000.	
TAXES	451000.	
SPARES	150000.	
ALLOWANCE FOR SHAKEDOWN	1695000.	
TOTAL INDIRECT COST		13456000.
CONTINGENCY		9471000.
CONTRACTOR FEE		2841000.
LAND COST		44000.
TOTAL CAPITAL INVESTMENT		59710000.
TOTAL INVESTMENT PER KW		119.42

LIME FGD

OPERATING COST

500 MW,LOW'S',W,HIGH BTU,90% REG

	QUANTITY	RATE	ANNUAL COST, $
RAW MATERIAL			
LIME	3.1 TON/HR	$ 40.20 /TON	715000.
FIXATION CHEMICAL	1.2 TON/HR	$ 20.00 /TON	146000.
UTILITIES			
WATER	538.2 GPM	$ 0.200 /MGAL	29000.
ELECTRICITY	16711.6 KW	25.00 MILLS/KWH	1903000.
REHEAT	92.0 MMBTU/HR	$ 1.25 /MMBTU	524000.
LABOR			
DIRECT LABOR	76.00 MANHR/DAY	$ 10.00 /MANHR	277000.
SUPERVISION	15 % OF DIRECT LABOR		42000.
MAINTENANCE			
LABOR AND MATERIAL	4.35 % OF TOTAL CAPITAL INVEST		2526000.
SUPPLIES	15 % OF LABOR AND MATERIAL		379000.
OVERHEAD			
PLANT	50 % OF OPERATING LABOR AND MAINT		1612000.
PAYROLL	20 % OF OPERATING LABOR		64000.
SLUDGE HANDLING	73000. TON-MILE/YR	$ 2.00 /TON-MILE	146000.

SUB TOTAL - OPERATION AND MAINTENANCE 8363000.

OPERATING COST (CONTD)

	ANNUAL COST, $	
FIXED CHARGES		
DEPRECIATION	1016000.	
TAXES	3961000.	
INSURANCE	213000.	
CAPITAL COSTS	8361000.	
SUB TOTAL - FIXED CHARGES		13551000.

500 MW 22 NG/J

NOV 7,1977 ESP COST PROGRAM

ESP DATA: ID NO. 015

TYPE = COLDSIDE	SCA = 278	INLET CONCENTRATION = NA GR/ACF
PLATE HEIGHT = 21.FT	TOTAL PLATE AREA = 428400.SQ FT	OUTLET CONCENTRATION = NA GR/ACF
PLATE LENGTH = 25.FT	GAS VELOCITY = 4FT/SEC	COLLECTION EFFICIENCY = 99.50%
ESP WIDTH = 103.FT	NO. OF PLATES = 408	TEMP AT INLET = 310.0DEG.F
ESP HEIGHT = 83.FT	ASPECT RATIO = 1.19	RETROFIT = EASY

THE ESP HAS 7 CHAMBERS, 4 FIELDS IN SERIES, AND 3 TR SETS PER FIELD.

FUEL DATA:

COAL TYPE = BITUMINOUS	NA2O = 0.00%
SULFUR = 3.48%	FE2O3 = 0.00%
ASH = 14.00%	
HEATING VALUE = 12000.BTU/LB	

SOURCE DATA: ID NO. 015

SOURCE TYPE = BOILER

GAS FLOW = 1540000.ACFM

SIZE = 500.00MW

CAPACITY FACTOR = 0.65

SYSTEM ASSUMPTIONS

- THE PROGRAM COST BASIS IS AUGUST 1976. AN ESCALATION FACTOR OF 1.335 IS USED TO UPDATE THE COSTS.

- THE FIXED CHARGES ARE CALCULATED USING THE PEDCO PROCEDURE FOR ANNUALIZING THE CAPITAL INVESTMENT.

- DUE TO WIDTH LIMITATIONS, THERE WILL BE NEEDED 3 DECKS OF ESP IN ORDER TO OBTAIN DESIRED RESULTS. THERE IS NO ADDITIONAL COST.

MAGNESIUM-OXIDE REGENERABLE FGD

CAPITAL INVESTMENT

500 MW,3.48% S,90% REG

	EQUIPMENT COST, $	
MGO PREPARATION		
MGO SILOS	198000.	
MGO CONVEYORS AND ELEVATORS	103000.	
TANKS AND AGITATORS	216000.	
PUMPS AND MOTORS	32000.	
	SUB TOTAL - MGO PREP	549000.
SO2 SCRUBBING		
ABSORBERS	22294000.	
FANS AND MOTORS	1937000.	
HEAT EXCHANGERS	3100000.	
SOOT BLOWERS	1196000.	
VALVES AND DUCTING	1619000.	
HOLD TANKS	1198000.	
PUMPS AND MOTORS	3327000.	
	SUB TOTAL - SO2 SCRUB	34671000.

CAPITAL INVESTMENT (CONTD)

SLURRY TREATMENT		
THICKENERS	1118000.	
CENTRIFUGES	2339000.	
SCREW CONVEYORS	90000.	
TANKS	15000.	
PUMPS AND MOTORS	79000.	
	SUB TOTAL - SLURRY TREAT	3641000.
CAKE DRYING AND CALCINATION		
DRYERS	1013000.	
CALCINERS	2702000.	
COKE EQUIPMENT	87000.	
CAKE EQUIPMENT	463000.	
DUST COLLECTORS	2877000.	
	SUB TOTAL - CAKE DRYING	7142000.
	TOTAL INSTALLED COST	46003000.
	RAW MATL INVENTORY	380000.

CAPITAL INVESTMENT (CONTD)

INDIRECT COSTS

INTEREST DURING CONSTRUCTION	4600000.	
FIELD OVERHEAD	4600000.	
ENGINEERING	4600000.	
FREIGHT	575000.	
OFFSITE	1380000.	
TAXES	690000.	
SPARES	230000.	
ALLOWANCE FOR SHAKEDOWN	2319000.	
TOTAL INDIRECT COST		18994000.
CONTINGENCY		13075000.
CONTRACTOR FEE		3923000.
BY PRODUCT PLANT COST		4926000.
TOTAL CAPITAL INVESTMENT		87301000.
TOTAL INVESTMENT PER KW		174.60

MAGNESIUM-OXIDE REGENERABLE FGD

OPERATING COST

500 MW,3.48% S,90% REG

	QUANTITY	RATE	ANNUAL COST, $
RAW MATERIAL			
MGO	0.78 TON/HR	$185.00 /TON	823000.
COKE	0.11 TON/HR	$125.00 /TON	79000.
FUEL OIL	41.28 BBL/HR	$ 15.00 /BBL	3526000.
UTILITIES			
WATER	621.3 GPM	$ 0.200 /MGAL	34000.
ELECTRICITY	20889.6 KW	25.00 MILLS/KWH	2379000.
REHEAT	92.0 MMBTU/HR	$ 1.25 /MMBTU	524000.
LABOR			
DIRECT LABOR	120.00 MANHR/DAY	$ 10.00 /MANHR	438000.
SUPERVISION	15 % OF DIRECT LABOR		66000.
MAINTENANCE			
LABOR AND MATERIAL	4.35 % OF TOTAL CAPITAL INVEST		3642000.
SUPPLIES	15 % OF LABOR AND MATERIAL		546000.
OVERHEAD			
PLANT	50 % OF OPERATING LABOR AND MAINT		2346000.
PAYROLL	20 % OF OPERATING LABOR		101000.
ASH HANDLING	0. TON-MILE/YR	$ 2.00 /TON-MILE	0.
		SUB TOTAL - OPERATION AND MAINTENANCE	14504000.

OPERATING COST (CONTD)

	QUANTITY	RATE	ANNUAL COST, $	
BY-PRODUCT CREDIT				
SULFURIC ACID	22.0 TON/HR	$ 20.00 /TON	2006000.	
			SUB TOTAL - BY-PRODUCT CREDIT	2006000.
FIXED CHARGES				
DEPRECIATION			1503000.	
TAXES			5858000.	
INSURANCE			316000.	
CAPITAL COSTS			12363000.	
			SUB TOTAL - FIXED CHARGES	20040000.

// XEQ FOOR2

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-450/3-78-007	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers		5. REPORT DATE Issued 2/78 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Larry L. Gibbs, Duane S. Forste, Yatendra M. Shah		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS PEDCo Environmental 11499 Chester Road Cincinnati, Ohio 45246		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-02-2535
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15. SUPPLEMENTARY NOTES

16. ABSTRACT

Cost cases developed include five processes, lime, limestone, mag-ox, double alkali, and Wellman-Lord; five plant sizes from 25-1000 MW; three SO_2 control levels, current, 90% efficiency, 0.5 lbs SO_2/million Btu; three particulate levels, current (43 ng/j), 22 ng/j, and 13 ng/j; and coals of varying sulfur, heating value, and ash content. Averaging times, redundancy, sludge disposal, and energy penalties are also studied.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution Cost Comparison Electric Utilities Sulfur Oxides Dust Control	Air Pollution Control Stationary Sources Coal-fired Boilers Emission Standards	13B
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