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Project Summary

Economics of Nitrogen Oxides, Sulfur Oxides, and Ash Control Systems for Coal-Fired Utility Power Plants

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An EPA-sponsored economic evaluation was made of three processes to reduce NO_x, SO_2, and ash emissions from coal-fired utility power plants; one based on a 3.5% eastern bituminous coal; and the other two, on 0.7% western subbituminous coal. NO_x control is based on an 80% reduction from current new source performance standards (NSPS); SO_2 and fly ash control are based on meeting the current NSPS. Selective catalytic reduction (SCR) is used for NO_x control with both coals. Limestone scrubbing and a cold-side electrostatic precipitator (ESP) are used with the 3.5% sulfur coal. Lime spray dryer flue gas desulfurization (FGD) and a baghouse for particulate collection are used with one 0.7% sulfur coal; and limestone scrubbing and a hot-side ESP, with the other. The economics consist of detailed breakdowns of the capital investments and annual revenue requirements. For systems based on a 500-MW power plant, capital investments range from \$167 to \$187 million (333 to 373 \$/kW) and first-year annual revenue requirements from \$54 to \$60 million (29 to 33 mills/kWh). The 3.5% sulfur coal case is highest because of the higher SO_2 control costs. The case with the spray dryer and baghouse is marginally lower in cost than that with limestone scrubbing and hot-side ESP. Costs for NO_x control range from 25 to 50% of the total costs, largely because of the high cost of the catalyst. The costs of the overall systems and the relationships of the component costs are complexly interrelated because of the interactions of the three processes.

This Project Summary was developed by EPA's Air and Energy Engineering Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

Most NO_x emission control requirements now in force are being met by modifications to the boiler combustion process, including: staged combustion (bias firing, burners out of service, and overfire air), flue gas recirculation, low excess air, and dual-register burner designs. Advanced burner and furnace designs now under development have the potential to provide significantly lower NO_x emissions than today's standards. These new combustion systems include fuel-staging and after-burning. However, these new designs are still several years from commercial availability. If stricter regulations were adopted in the near future, these combustion modification methods would not—at least for several years—be adequate, and flue gas treatment would be necessary. The most highly developed method of flue gas treatment for NO_x control is selective catalytic reduction (SCR) in which flue gas is treated with ammonia and passed over a solid catalyst to reduce the NO_x to molecular nitrogen. The need for flue gas treatment to meet NO_x emission limits would probably be met by the use of SCR processes, several variants of which are offered commercially. A generic SCR process, derived from these commercial processes, is therefore used in all three cases.

Limestone scrubbing remains the predominant method of flue gas desulfurization (FGD), increasingly with provisions to produce gypsum by forced or natural oxidation to reduce waste disposal problems. The use of low-sulfur coal has, however, led to the rapid adoption of spray dryer FGD in which the flue gas is contacted with a fine spray of absorbent that evaporates to solid particles in the spray dryer and can be collected as a solid. More than a dozen spray dryer FGD systems have been selected by utilities for low- and medium-sulfur coal applications in the last 5 years. This trend is represented by the use of a lime-based spray dryer system in case 2, one of the low-sulfur coal cases. For case 1, the high-sulfur coal case, and case 3, the other low-sulfur coal case, conventional limestone FGD systems producing gypsum are used.

The use of low-sulfur coal has also led to the adoption of new methods of fly ash control because the ash is difficult to collect in conventional cold-side (after the boiler air heater) electrostatic precipitators (ESPs) that have served as the industry standard for many years. In many such cases, hot-side (before the air heater) ESPs have been used because the higher ash temperature improves the electrical properties of the ash that affect the efficiency of collection. In both cases, however, strict fly ash emission regulations (e.g., the 1979 NSPS) strained the capabilities of then-existing ESP technology, leading to the rapid adoption of fabric filter baghouses for fly ash control. Baghouses, which are proving quite effective, have also been the predominant choice for use with spray dryer FGD in which the fly ash and FGD wastes are collected together. These uses are represented by a conventional cold-side ESP in case 1, a baghouse in case 2, and a hot-side ESP in case 3.

Process Descriptions

The base case designs are applied to a new 500-MW boiler fired with pulverized coal that operates 5,500 hr/yr for 30 years. The boiler meets the 1979 NSPS NO_x emission requirements by combustion modifications. The emission control systems are designed for an 80% reduction in these NO_x emissions and for reduction of SO_2 and fly ash emissions of the 1979 NSPS levels. The designs upon which the costs are based include all equipment involved in the collection and disposal of wastes, including a common onsite landfill, and all boiler modifications—air heater modifications and larger induced-draft (ID) fans—made necessary by the presence of the emission control systems. Major conditions are shown in Table 1.

The SCR systems consist of two trains of insulated reactors with ash hopper bottoms (except in case 3 with an upstream ESP) and provisions for changing catalyst beds. The beds are composed of 0.15- by 0.15- by 1-m honeycomb blocks in metal modules. Flue gas is ducted from economizer (or hot-side ESP) outlet and returned to the air heater. Modifications to the air heater to accommodate ammonia salt buildup are included. An ammonia storage and handling system to inject an ammonia/air mixture in the inlet duct is provided. An economizer bypass to maintain the reactor temperature during low-load operation is included. The catalyst life is assumed to be 1 year, with changes during scheduled boiler outages.

The limestone FGD systems consist of multiple trains of spray tower absorbers connected to a common inlet plenum and discharging to the stack plenum. Each train consists of a presaturator, the absorber with a hold tank and the associated absorbent recirculation system (and an oxidation tank in case 1), and a booster fan. A steam reheater is included in case 1 to provide a stack temperature of 175°F. Flue gas is bypassed in the low-sulfur coal case to eliminate reheating costs (in this case, a less expensive alternative than full scrubbing at the low removal efficiency required). A single slurry preparation area supplies the system. The gypsum waste is dewatered in a thickener and rotary vacuum filters and trucked 1 mile to the landfill. A spare absorber train and emergency bypasses for half of the scrubbed flue gas are provided in all cases. A similar arrangement is used for the spray dryer system in case 2, except that the baghouse booster fans also serve for the spray dryer system. The spray dryers are cylindrical vessels with conical bottoms with single rotary atomizers. The absorbent slurry consists

Table 1. *Major Design Conditions*

	Case 1	Case 2	Case 3
Coal and boiler conditions			
Coal	East. bit.	West. subbit.	West. subbit.
Coal sulfur, % as fired	3.36	0.48	0.48
Coal ash, % as fired	15.1	6.3	6.3
Btu/lb, as fired	11,700	8,200	8,200
Sulfur emitted, % of total	92	85	85
Fly ash, % of total ash	80	80	80
NO_x emitted, lb/10^6 Btu*	0.6	0.5	0.5
Boiler size[a], MW	500	500	500
Heat rate, Btu/kWh	9,500	10,500	10,500
Emission control			
No_x control	SCR	SCR	SCR
No_x reduction, %	80	80	80
So_2 control	Limestone FGD	Lime spray dryer	Limestone FGD
Absorber trains[b]	5	4	5
Bypassed flue gas, %	0	12	28
SO_2 removal, overall %	89	65	65
SO_2 removal, absorber %	89	73	90
Fly ash control	Cold-side ESP	Baghouse	Hot-side ESP
Fly ash removal, %c	99.7	99.9	99.6

a. Based on coal consumption and heat rate.
b. Including one spare train.
c. In collection device, excluding upstream fallout.

*Readers more familiar with metric units are asked to use the conversion factors provided at the end of this Summary.

of slaked lime and recycled solids from the baghouse.

The ash control systems consist of the ESPs or baghouses (two parallel identical units), hoppers, conveying systems, a bottom ash dewatering system, storage silos for fly ash, and equipment for trucking the waste to the landfill. The bottom ash is collected in a conventional hopper and sluiced to the dewatering system. Fly ash is conveyed to silos with a vacuum-pneumatic system. The mixed fly ash and FGD waste in case 2 is conveyed by a pressure-vacuum pneumatic system.

Economic Procedures

The economics consist of the capital investment in 1982 dollars and the first-year and levelized annual revenue requirements in 1984 dollars. The annual revenue requirements consist of operating and maintenance costs plus capital charges. The capital charges are levelized in both the first-year and levelized annual revenue requirements; whereas, the operating and maintenance costs are also levelized in the latter. The levelizing factor in all cases is 1.886, which represents a 6% annual inflation and a 10% discount rate over the 30-year life of the project

Costs include all those associated with the construction and operation of the systems, including modifications to the boiler air heater and the incremental increase in the boiler ID fans to account for the pressure drop in the emission control equipment that is not compensated for by separate booster fans. Construction and operating costs of the landfill are also included.

Costs are divided into three sections, representing NO_x, SO_2, and ash control, and are further divided into categories representing particular unit operations within the processes. Where equipment or operations serve more than one process (incremental increases in boiler ID fans and the common landfill, for example), the costs are prorated using the appropriate factors (pressure drops or waste volume, for example). Baghouse costs are not prorated, however, because of the effect of flue gas volume on baghouse costs.

Results

Capital investments and annual revenue requirements are summarized in Tables 2 through 5. With the choice of processes determined, at least in part by the type of coal, and the costs of the individual processes influenced by

Table 2. *Summary of Capital Investments in $\$10^6$* [a,b]

	Capital investment, mid-1982 $			
	$10⁶			
	NO_x	SO_2	Particulate	Total
Base case, 500 MW, 80% NO_x removal				
Case 1	41.9	101.8	42.9	186.6
Case 2	50.1	54.0	62.6	166.7
Case 3	48.1	69.4	53.5	171.0
Case variation, 200 MW, 80% NO_x removal				
Case 1	20.6	58.2	22.6	101.5
Case 2	24.2	31.7	31.4	87.3
Case 3	24.3	41.4	27.8	93.5
Case variation, 1,000 MW, 80% NO_x removal				
Case 1	77.7	175.7	73.3	326.6
Case 2	94.8	97.4	110.7	302.9
Case 3	91.2	121.1	94.6	306.9
Case variation, 500 MW, 90% NO_x removal				
Case 1	48.2	101.9	42.9	193.0
Case 2	55.5	54.0	62.7	172.2
Case 3	53.9	69.4	53.5	176.8

[a] *Table 1 lists the major design conditions for each case.*
[b] *All values have been rounded; therefore, totals do not necessarily correspond to the sum of the individual values indicated.*

Table 3. *Summary of Capital Investments in $/KW* [a,b]

	Capital investment, mid-1982 $			
	$/kW			
	NO_x	SO_2	Particulate	Total
Base case, 500 MW, 80% NO_x removal				
Case 1	83.7	203.7	85.8	373.2
Case 2	100.2	108.0	125.3	333.4
Case 3	96.1	138.7	107.1	342.0
Case variation, 200 MW, 80% NO_x removal				
Case 1	103.1	291.0	113.2	507.3
Case 2	121.0	158.3	157.2	436.6
Case 3	121.6	206.9	139.0	467.5
Case variation, 1,000 MW, 80% NO_x removal				
Case 1	77.7	175.7	73.3	326.6
Case 2	94.8	97.4	110.7	302.9
Case 3	91.2	121.1	94.6	306.9
Case variation, 500 MW, 90% NO_x removal				
Case 1	96.4	203.8	85.8	386.0
Case 2	111.0	108.0	125.4	344.3
Case 3	107.8	138.8	107.1	353.6

[a] *Table 1 lists the major design conditions for each case.*
[b] *All values have been rounded; therefore, totals do not necessarily correspond to the sum of the individual values indicated.*

Table 4. *Summary of Annual Revenue Requirements in $\$10^6$ [a,b]*

	Annual revenue requirements, 1984 $							
	First year $\$10^6$				Levelized $\$10^6$			
	NO_x	SO_2	Particulate	Total	NO_x	SO_2	Particulate	Total
Base case, 500 MW, 80% NO_x removal								
Case 1	21.9	28.8	9.8	60.4	35.8	41.0	12.8	89.7
Case 2	26.5	12.7	14.4	53.6	43.5	16.9	19.0	79.4
Case 3	24.7	18.0	12.1	54.8	40.4	24.9	15.8	81.0
Case variation, 200 MW, 80% NO_x removal								
Case 1	9.7	16.3	5.2	31.2	15.6	23.1	6.9	45.6
Case 2	11.6	7.6	7.7	26.8	18.7	10.1	10.4	39.2
Case 3	11.1	11.0	6.6	28.7	17.8	15.3	8.8	41.9
Case variation, 1,000 MW, 80% NO_x removal								
Case 1	41.5	48.8	16.1	106.4	68.1	69.2	20.9	158.2
Case 2	51.2	22.2	24.5	97.9	84.2	29.2	31.8	145.1
Case 3	47.9	30.3	20.5	98.7	78.4	41.4	26.4	146.3
Case variation, 500 MW, 90% NO_x removal								
Case 1	26.1	28.8	9.8	64.6	42.9	41.0	12.8	96.7
Case 2	30.1	12.7	14.4	57.2	49.5	16.9	19.0	85.4
Case 3	28.6	18.0	12.1	58.6	46.8	24.9	15.8	87.5

[a]Table 1 lists the major design conditions for each case.
[b]All values have been rounded; therefore, totals do not necessarily correspond to the sum of the individual values indicated.

Table 5. *Summary of Annual Revenue Requirements in Mills/KWH[6] [a,b]*

	Annual revenue requirements, 1984 $							
	First year				Levelized			
	Mills/kWh							
	NO_x	SO_2	Particulate	Total	NO_x	SO_2	Particulate	Total
Base case, 500 MW, 80% NO_x removal								
Case 1	8.0	10.5	3.5	22.0	13.0	14.9	4.7	32.6
Case 2	9.6	4.6	5.2	19.5	15.8	6.2	6.9	28.9
Case 3	9.0	6.5	4.4	19.9	14.7	9.0	5.7	29.5
Case variation, 200 MW, 80% NO_x removal								
Case 1	8.8	14.8	4.7	28.4	14.2	21.0	6.3	41.5
Case 2	10.6	6.9	7.0	24.4	17.0	9.2	9.4	85.7
Case 3	10.1	10.0	6.0	26.1	16.2	13.9	8.0	38.1
Case varaition, 1,000 MW, 80% NO_x removal								
Case 1	7.5	8.9	2.9	19.3	12.4	12.6	3.8	28.8
Case 2	9.3	4.0	4.5	17.8	15.3	5.3	5.8	26.4
Case 3	8.7	5.5	3.7	18.0	14.3	7.5	4.8	26.6
Case variation, 500 MW, 90% NO_x removal								
Case 1	9.5	10.5	3.5	23.5	15.6	14.9	4.7	35.2
Case 2	10.9	4.6	5.2	20.8	18.0	6.2	6.9	31.1
Case 3	10.4	6.5	4.4	21.3	17.0	9.0	5.7	31.8

[a]Table 1 lists the major design conditions for each case.
[b]All values have been rounded; therefore, totals do not necessarily correspond to the sum of the individual values indicated.

other processes in the system, economic comparisons on a process-by-process basis must be interpreted with care, as seen in the detailed breakdown of the base case costs.

Base Case Capital Investments

Breakdowns of the base case capital investments are shown in Table 6. The case 1 (3.5% sulfur coal, SCR, limestone FGD, and cold-side ESP) capital investment is $187 million (373 $/kW), of which NO_x control accounts for 22% of the total; SO_2 control, 55%; and particulate control, 22%. The case 2 (0.7% sulfur coal, SCR, spray dryer FGD, and baghouse) capital investment is $167 million (333 $/kW), and the breakdown is 30%, 32%, and 38%. The case 3 (0.7% sulfur coal, hot-side ESP, SCR, and limestone FGD) capital investment is $171 million (342 $/kW), and the breakdown is 28%, 40%, and 32%. The low percentage for SO_2 control in case 2 with the spray dryer results from the particulate collection costs for FGD waste being combined with the fly ash collection costs and assigned to particulate control costs.

NO_x Control

For NO_x control, the most important capital cost is the initial catalyst charge, which is almost one-third of the total capital investment. Most of the remaining capital costs are for the reactor and the associated internal and external catalyst supports and handling system, and for the incremental fan cost and flue gas ductwork associated with flue gas handling. The remaining capital costs—ammonia storage and injection system, air heater modification, waste disposal (of spent catalyst), land, and royalties—are relatively minor. Incremental fan costs are minor; 90% of the flue gas-handling costs is for ductwork.

Most of the capital costs are directly related to the flue gas volume, particularly for the major cost areas. As a result, the total capital investment for NO_x control in case 1 is lowest because of lower flue gas volume with the high-Btu coal. Case 3 is slightly lower than case 2 because of the absence of fly ash.

Air heater modification costs are associated with the increase in size, the more tightly packed elements, and the use of thicker and more corrosion-resistant elements.

The ammonia storage and injection costs are almost the same for all three cases. The only cost differences result from differences in the injection grid, which vary with the flue gas duct size and design.

SO_2 Control

The capital investments for SO_2 control are highest for case 1 and lowest for case 2, but the capital investment for case 2 does not contain the costs for FGD waste collection. In all three cases, most of the costs are associated with the SO_2 absorption area (the absorbers and the absorbent liquid system or the spray dryers) and the flue gas-handling area (fans and ductwork). These two areas account for 65% of the process equipment costs in case 1 and about 80% of the process equipment costs in cases 2 and 3.

The higher capital investment for case 1 (as compared with case 3) is almost entirely related to the larger quantities of SO_2 removed. The materials handling (limestone), feed preparation,

Table 6. *Base Case Capital Investment Comparison*[a]

Process capital	Case 1, $1000s				Case 2, $1000s				Case 3, $1000s			
	NO_x	SO_2	Particulate	Total	NO_x	SO_2	Particulate	Total	NO_x	SO_2	Particulate	Total
NH_3 storage and injection	1,314			1,314	1,328			1,328	1,297			1,297
Reactor	7,829			7,829	9,278			9,278	8,453			8,453
Flue gas handling	3,843	11,343	1,311	16,497	4,543	7,374	4,961	16,878	5,386	11,175	4,290	20,851
Air heater	819			819	1,220			1,220	861			861
Materials handling		2,528		2,528		1,132		1,132		1,266		1,266
Feed preparation		4,717		4,717		1,258		1,258		2,363		2,363
SO_2 absorption		20,411		20,411		12,992		12,992		18,070		18,070
Oxidation		2,677		2,677								
Reheat		3,653		3,653								
Solids separation		3,681		3,681						2,265		2,265
Lime particulate recycle						2,140		2,140				
Particulate removal and storage			10,509	10,509			15,446	15,446			14,354	14,354
Particulate transfer			5,636	5,636			6,779	6,779			4,378	4,378
Total process capital, $1000s	13,805	49,010	17,456	80,271	16,369	24,896	27,186	68,451	15,997	35,139	23,022	74,158
Other Capital Investment												
Waste disposal direct investment	19	4,011	3,344	7,374	34	527	2,749	3,310	30	847	2,628	3,505
Land	10	458	377	845	15	75	326	416	15	113	313	441
Catalyst	12,028			12,028	14,678			14,678	13,455			13,455
Royalty	463			463	563			563	563			563
Other[b]	15,530	48,360	21,710	85,600	18,431	28,478	32,388	79,297	18,001	33,272	27,583	78,856
Total, $1000s	41,855	101,839	42,887	186,581	50,090	53,976	62,649	166,715	48,061	69,371	53,546	170,978
Total, $/kW[c]	83.7	203.7	85.8	373.2	100.2	108.0	125.3	333.4	96.1	138.7	107.1	342.0

[a]Table 1 lists the major design conditions for each case.
[b]Consists of costs for "services, utilities, and miscellaneous;" all six items of "indirect investment;" "allowance for start-up and modifications;" "interest during construction;" and "working capital" as listed in the appendix tables of the full report.
[c]All values have been rounded; therefore, totals do not necessarily correspond to the sum of the individual values indicated.

and solids separation area costs are roughly two times higher and waste disposal costs are almost five times higher for case 1 than for case 3. In addition, the SO_2 removal requirements in case 1 require both full scrubbing—necessitating steam reheat of the flue gas—and forced oxidation, neither of which is necessary in case 3.

SO_x control in case 2 is the least expensive, primarily because of lower costs in the SO_2 absorption area (because there is no liquid recirculation system) and in the flue-gas-handling areas (because of the lower pressure drop in the spray dryers and the economy of scale with fan costs prorated between SO_2 and particulate control). An accurate comparison of SO_2 control capital investment in cases 2 and 3, however, must include the costs of particulate collection, which are discussed in the following section.

Particulate Control

The capital investments for particulate control are $43 million for case 1, $63 million for case 2, and $54 million for case 3. In all three cases, the particulate removal and storage area accounts for about 60% of the total particulate control process equipment costs, with the ESPs or baghouses and their hoppers accounting for most of the area cost. The cold-side ESPs of case 1 have an installed cost of $5.9 million, and the hot-side ESPs of case 3 have an installed cost of $9.8 million. Most of this difference is a result of the larger flue gas volume in case 3—both in an absolute sense and because the ESPs in case 3 operate at a higher temperature. The baghouses have an installed cost of $7.4 million. Much of the cost difference between cases 2 and 3 is a result of the larger size of the baghouses and the corresponding larger and more complex hoppers required.

Particulate transfer process equipment costs are $5.6 million for case 1, $6.8 million for case 2, and $4.4 million for case 3. Case 2 has a more complicated pressure-vacuum conveying system, which accounts for most of the cost difference between cases 2 and 3.

Flue-gas-handling costs are $1.3 million for case 1, $5.0 million for case 2, and $4.4 million for case 3. The lower costs for case 1 result from the smaller absolute volume and lower temperature of the flue gas. In addition, the costs for cases 1 and 3 are almost totally composed of the cost of ductwork since the incremental fan costs are negligible. In the case of the baghouses, however, fan costs are significant, about equal to ductwork costs, because of the large pressure drop through the baghouses.

Base Case Comparisons - Annual Revenue Requirements

The base case annual revenue requirements are shown in Table 7. The first-year annual revenue requirements for case 1 (3.5% sulfur coal, SCR, limestone FGD, and cold-side ESP) are $60 million (22 mills/kWh) with 36% associated with NO_x control, 48% with SO_2 control, and 16% with particulate control. For case 2 (0.7% sulfur coal, SCR, spray dryer FGD, and baghouse), the first-year annual revenue requirements are $54 million (19.5 mills/kWh) with 49% associated with NO_x control, 24% with SO_2 control, and 27% with particulate control. For case 3 (0.7% sulfur coal, hot-side ESP, SCR, and limestone FGD), the first-year annual revenue requirements are $55 million (19.9 mills/kWh) with 45% associated with NO_x control, 33% with SO_2 control, and 22% with particulate control.

The levelized annual revenue require-

Table 7. *Annual Revenue Requirement Element Analysis for Base Cases*

500-MW Unit with 80% NO_x Removal[a]

	Case 1				*Case 2*				*Case 3*			
Direct costs	*NO_x*	*SO_2*	*Particulate*	*Total*	*NO_x*	*SO_2*	*Particulate*	*Total*	*NO_x*	*SO_2*	*Particulate*	*Total*
Ammonia	364			364	336			336	336			336
Catalyst	13,899			13,889	16,962			16,962	15,549			15,549
Lime/limestone		1,216		1,216		708		708		186		186
Operating labor and supervision												
Process	66	658	230	954	66	263	296	625	66	594	230	890
Landfill	3	523	436	962	5	83	435	523	4	127	393	524
Steam	51	1,369		1,420	65			65	63			63
Electricity	278	2,146	581	3,005	492	780	966	2,238	391	1,477	993	2,861
Fuel	1	162	135	298	1	18	95	114	1	28	87	116
Maintenance	586	4,276	1,025	5,887	695	1,599	1,811	4,105	679	3,005	1,299	4,983
Analysis	46	104	6	156	46	88	6	140	46	69	6	121
Other	13	27	19	59	17	16	36	69	41	19	36	96
Total direct costs, $1000	15,307	10,481	2,432	28,220	18,685	3,555	3,645	25,885	17,176	5,505	3,044	25,725
INDIRECT COSTS												
Overheads	421	3,337	1,018	4,776	487	1,220	1,529	3,236	477	2,277	1,157	3,911
Capital charges	6,153	14,970	6,304	27,427	7,363	7,934	9,209	24,506	7,065	10,198	7,871	25,134
Total first-year annual revenue requirements												
$1000s	21,881	28,788	9,754	60,423	26,535	12,709	14,383	53,627	24,718	17,980	12,072	54,770
Mills/kWh[b]	8.0	10.5	3.5	22.0	9.6	4.6	5.2	19.5	9.0	6.5	4.4	19.9
Levelized annual revenue requirements												
$1000s	35,816	41,031	12,811	89,658	43,521	16,940	18,967	79,428	40,359	24,875	15,794	81,028
Mills/kWh[b]	13.0	14.9	4.7	32.6	15.8	6.2	6.9	28.9	14.7	9.0	5.7	29.5

[a]*Table 1 lists the major design conditions for each case.*
[b]*All values have been rounded; therefore, totals do not necessarily correspond to the sum of the individual values indicated.*

ments are \$90 million (33 mills/kWh), \$79 million (29 mills/kWh), and \$81 million (30 mills/kWh) for cases 1, 2, and 3, respectively. For cases 1, 2, and 3, respectively, 40%, 55%, and 50% of the total levelized annual revenue requirements are associated with NO_x control; 46%, 21%, and 31% with SO_2 control; and 14%, 24%, and 19% with particulate control.

The cost per ton of pollutant removed is presented for the base cases in Table 8 based on each of first-year and levelized annual revenue requirements. A comparison on this basis indicates that NO_x control is significantly less cost effective than SO_2 and particulate control. For example, with first-year annual revenue requirements, the costs in Table 8 range from about 3,500 \$/ton to 4,600 \$/ton for NO_x control, from about 500 \$/ton to over 1,900 \$/ton for SO_2 control, and from 60 \$/ton to 130 \$/ton for particulate control.

Table 8. *Cost per Ton of Pollutant Removed for Base Cases*

500-MW Unit with 80% NO_x Removal

\$/ton, 1984 \$

	First year			Levelized		
	NO_x	SO_2	Particulate	NO_x	SO_2	Particulate
Case 1	3,490	470	60	5,710	670	80
Case 2	4,600	1,370	130	7,540	1,820	170
Case 3	4,280	1,930	110	6,990	2,680	140

NO_x Control

The first-year annual revenue requirements for the NO_x control processes in cases 1, 2, and 3, respectively, are \$22 million (8 mills/kWh), \$27 million (10 mills/kWh), and \$25 million (9 mills/kWh). In all cases, the catalyst replacement costs are the overwhelmingly dominant cost elements; over 90% of the direct costs and two-thirds of the total annual revenue requirements are for the yearly replacement of catalyst. Except for this cost, the annual revenue requirements are modest, appreciably less than the costs for similar cost categories for SO_2 and particulate control.

SO_2 Control

The first-year annual revenue requirements for the SO_2 control processes are \$29 million (11 mills/kWh), \$13 million (5 mills/kWh), and \$18 million (7 mills/kWh) for cases 1, 2, and 3, respectively. Again, case 2 with the spray dryer does not include costs associated with operation of the baghouse. Excluding capital charges (which are proportional to capital investment) and overheads (which are proportional to the direct costs), the direct costs of the annual revenue requirements reflect appreciably wider differences in operating costs. The direct costs are \$10.5 million, \$3.6 million, and \$5.5 million for cases 1, 2, and 3, respectively. Maintenance costs are the highest element of direct costs in all three cases, followed again in all three cases by electricity costs. Steam for reheating the flue gas is the third largest direct cost (13% of the total) in case 1, a cost not incurred by cases 2 and 3, which have bypass reheat. These costs and the remaining direct costs are all higher for case 1 than the corresponding costs for cases 2 and 3, a result of the large quantity of SO_2 removed for case 1. With the exception of lime costs, which are 20% of the total direct costs, case 2 has lower direct costs in every category as compared with case 3.

Particulate Control

The first-year annual revenue requirements for particulate control are \$10 million (4 mills/kWh), \$14 million (5 mills/kWh), and \$12 million (4 mills/kWh) for cases 1, 2, and 3, respectively. The annual revenue requirements for case 2, however, also include the collection of the spray dryer FGD solids. Among the direct costs, maintenance costs are the highest direct cost in all three cases, followed by electricity costs and labor costs. Maintenance costs are highest for case 2, which are about 75% higher than case 1 and 40% higher than case 3. Electricity costs are lowest for case 1 and highest for case 3, while case 2 has only slightly lower electricity costs than case 3. Labor costs do not differ appreciably, although process labor in case 2 is about 25% higher than in cases 1 and 3.

Energy Requirements

The energy consumptions of the base cases, expressed in Btu equivalents, are shown in Table 9. The total energy requirements range from 4.89% of the boiler capacity for case 1 to 2.31% of the boiler capacity for case 2. The NO_x control energy requirements are the lowest in all three cases and most are for the incremental electricity consumption of the boiler ID fan that compensates for the relatively small pressure loss in the reactors. For SO_x control, cases 1 and 3 have large electricity requirements because of the FGD booster fans and the pumping requirement for the absorbent liquid recirculation systems. These are similar in both cases. The electricity requirements for the spray dryer in case 2 are lower because there is no liquid recirculation system. Particulate control energy requirements in cases 1 and 3 are mostly for ESP electricity, which is substantially lower for the cold-side ESP. In case 2, most of the electricity is for the booster ID fans that compensate for the relatively higher pressure drop in the baghouse.

Power Unit Size Case Variation

The capital investments and annual revenue requirements of systems for 200-MW, 500-MW, and 1,000-MW systems are shown in Tables 2 through 5. Compared with the 200-MW systems, the 500-MW systems are 83% to 91% higher and the 1,000-MW systems are 222% to 247% higher in capital investment. In terms of \$/kW, the 1,000-MW systems are about one-third less expensive, however, because of the economy of scale. The general relationships of the three cases remain the same at all three power unit sizes. The rate of capital investment increase is greatest for the NO_x control processes (an increase of 275% to 292% between the 200-MW and 1,000-MW sizes, as compared with 193% to 207% for the SO_2 control processes and 224% to 253% for the particulate control processes), and it is also higher for the spray dryer FGD process and the baghouse than for the limestone FGD process and ESPs. As a result, the rate of capital investment increase with size is greatest for case 2.

Compared with the 200-MW systems, the annual revenue requirements of 500-MW systems are 91% to 100% higher, the 1,000-MW systems are 241% to 265% higher, and there is approximately a one-third reduction in costs in terms of \$/kWh. As with capital investment, the annual revenue requirements retain the same general relationships at the three power unit sizes, the rates of increase for the NO_x control processes are higher (328% to 341% between the 200-MW and the 1,000-MW sizes, compared with 175% to 199% for the SO_2 control processes and 210% to 218% for the particulate control processes) and the rates for the spray dryer FGD and baghouse are higher than those of the limestone FGD systems and ESPs.

2-Year Catalyst Life Case Variation

To illustrate the effect of catalyst life on annual revenue requirements, the annual revenue requirement for the three 500-MW base cases were also determined for a 2-year catalyst life. The only change in NO_x control annual revenue requirements is a reduction in the catalyst cost by 50%—$7.0 million, $8.5 million, and $7.8 million for cases 1, 2, and 3, respectively. The longer catalyst life reduces the annual revenue requirements of NO_x control by one-third. The annual revenue requirements of the overall systems are reduced by 12% to 16%.

90 Percent NO_x Reduction Case Variation

To evaluate the economic effects of a 90% reduction in NO_x, as compared with the 80% used in the other evaluations, the economics of the three 500-MW cases were determined with 90% NO_x reduction. The primary differences from the base case conditions are an NH_3:NO_x ratio of 0.91:1.0 instead of 0.81:1.0, a 12% increase, and an increase in catalyst (based on vendor recommendations) of 22.5% for case 1, 15.0% for case 2, and 18.0% for case 3. The capital investments of the NO_x control processes are increased 11% to 15% and the total for the three systems by 3% to 4%, all of which is a result of the increase in NO_x reduction. The first-year annual revenue requirements for the NO_x process are increased 19%, 14%, and 16% for cases 1, 2, and 3, respectively. The effect on the annual revenue requirements of the overall system of increasing the NO_x from 80% to 90% is an increase of 7% in all three cases.

Ammonia Price Case Variation

Changes in the price of ammonia would have little effect on the overall cost of the NO_x control process. The annual revenue requirements for the NO_x control processes (in the 500-MW base case) increase only 1.5% to 1.9% as the ammonia price is doubled from the base case value of 155 $/ton to 310 $/ton.

Table 9. Comparison of Base Case Energy Requirements

Case	*Steam, 10^6 Btu/hr*	*Electricity, 10^6 Btu/hr*	*Diesel fuel, 10^6 Btu/hr*	*Percent of power unit, input energy*
Case 1[a]				
NO_x	*3.15*	*12.97*	*0.01*	*0.34*
SO_x	*83.79*	*100.20*	*2.65*	*3.93*
Particulate	*0.00*	*27.14*	*2.20*	*0.62*
Total	*86.94*	*140.31*	*4.86*	*4.89*
Case 2[b]				
NO_x	*4.00*	*25.40*	*0.02*	*0.56*
SO_x	*0.00*	*40.26*	*0.30*	*0.77*
Particulate	*0.00*	*49.85*	*1.55*	*0.98*
Total	*4.00*	*115.51*	*1.87*	*2.31*
Case 3[b]				
NO_x	*3.88*	*20.18*	*0.02*	*0.46*
SO_x	*0.00*	*76.20*	*0.46*	*1.46*
Particulate	*0.00*	*51.22*	*1.41*	*1.00*
Total	*3.88*	*147.60*	*1.89*	*2.92*

Note: Does not include energy requirement represented by raw materials.

[a]Based on a 500-MW boiler, a gross heat rate of 9,500 Btu/kWh for generation of electricity, and a boiler efficiency of 90% for generation of steam.

[b]Based on a 500-MW boiler, a gross heat rate of 10,500 Btu/kWh for generation of electricity, and a boiler efficiency of 90% for generation of steam.

Conclusions

The total costs for case 1, based on 3.5% sulfur coal, and cases 2 and 3, based on 0.7% sulfur coal, differ less than 15% in capital investment and annual revenue requirements in spite of the differing control processes. This is a result in part of offsetting differences—the much higher SO_2 control costs for case 1 are offset by lower fly ash control costs and a smaller flue gas volume. The costs for the two low-sulfur coal cases, one with a spray dryer FGD system and baghouse and the other with limestone FGD and a hot-side ESP, differ only marginally in cost. In the two low-sulfur coal cases, the low spray dryer FGD costs and the advantage of combined particulate collection are offset by the higher NO_x control costs and higher baghouse costs. When only the SO_2 and fly ash control costs are compared, the spray dryer-baghouse case is 5% lower in capital investment and 12% lower in annual revenue requirements than the hot-side ESP and limestone FGD case.

The combined emission control processes increase the power plant capital investment by about 35% on the average, of which the NO_x portion is about one-third. Base on levelized annual revenue requirements, the average increase in the cost of power is about 45%, of which the NO_x portion is about half.

The energy requirements of 2% to 5% of the boiler input energy are mostly for SO_2 and particulate control. For the cases with limestone FGD, SO_2 control has the highest energy requirements.

The use of flue gas treatment for NO_x control, such as the SCR process in this study, would add significantly to emission control costs. An SCR process for a 500-MW power plant would have a capital investment of 80 to 100 $/kW and annual revenue requirements of 8 to 9 mills/kWh. The high cost is largely associated with the catalyst replacement cost, which accounts for 90% of the direct costs in annual revenue requirements. A 2-year catalyst life reduces the annual revenue requirements by over one-third, however, so the costs for NO_x control in this study, which are based on a 1-year life, could be substantially reduced if extended catalyst lives are attained.

Other than catalyst life, the main factor affecting NO_x control costs is the flue gas volume which determines the fan and ductwork costs and the catalyst volume. Increasing the NO_x reduction efficiency from 80% to 90% increases the costs by 10% to 20%, again because of the larger catalyst volume needed. Ammonia costs have almost no effect on costs; doubling the price of ammonia increases the annual revenue requirements by about 2%.

Although the costs of NO_x control are in the same general range as those for SO_2 and fly ash control, if the processes are compared on the basis of the pounds of pollutants reduced, the costs for NO_x control are 2 to 10 times greater than for SO_2 control and 40 to 60 times greater than for ash control.

In SO_2 control, the major costs are associated with the absorption area and flue gas handling (ductwork and fans). These costs do not differ greatly among the three cases because of offsetting differences—a larger cost for liquid circulation in the high-sulfur coal case but a larger flue gas volume in the low-sulfur coal cases, which requires larger equipment and has larger fan costs. The higher costs for the high-sulfur coal case are in large part the result of the much larger quantity of sulfur removed: the materials-handling, waste-handling, and disposal costs are two to five times higher for the high-sulfur coal case than for the low-sulfur coal case with limestone FGD.

Conversion Factors

Certain non-metric units are used in this Summary for the reader's convenience. Readers who are more familiar with metric units may use the following to convert to that system:

Non-metric	Times	Yields metric
Btu	1.06	kJ
°F	5/9(°F-32)	°C
lb	0.454	kg
mi	1.61	km
ton	907.2	kg

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The complete report, entitled "Economics of Nitrogen Oxides, Sulfur Oxides, and Ash Control Systems for Coal-Fired Utility Power Plants," (Order No. PB 85-243 103/AS; Cost: $28.95, subject to change) will be available only from:

National Technical Information Service
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