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Project Summary

Retrofit Costs for SO_2 and NO_x Control Options at 200 Coal-Fired Plants

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This report documents the results of a study to significantly improve engineering cost estimates currently being used to evaluate the economic effects of applying sulfur dioxide (SO_2) and nitrogen oxides (NO_x) controls at 200 large SO_2- emitting coal-fired utility plants. To accomplish the objective, procedures were developed and used that account for site-specific retrofit factors. The site-specific information was obtained from aerial photographs, generally available data bases, and input from utility companies. Cost estimates are presented for six control technologies: lime/limestone flue gas desulfurization, lime spray drying, coal switching and cleaning, furnace and duct sorbent injection, low NO_x combustion or natural gas reburn, and selective catalytic reduction. Although the cost estimates provide useful site-specific cost information on retrofitting acid gas controls, the costs are estimated for a specific time period and do not reflect future changes in boiler and coal characteristics (e.g., capacity factors and fuel prices) or significant changes in control technology cost and performance.

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

The National Acid Precipitation Assessment Program (NAPAP) is responsible for developing cost and performance information on various methods for reducing the emissions of acid rain precursors. Coal-fired utility boilers are major emitters of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). However, estimating the cost and performance of SO_2 and NO_x controls for coal-fired power plants is difficult due to differences in plant layout and boiler design.

The objective of this study was to significantly improve the accuracy of engineering cost estimates used to evaluate the economic effects of applying SO_2 and NO_x controls at 200 large SO_2-emitting coal-fired utility plants. This project was conducted in four phases as shown in Figure 1. In Phase I, detailed, site-specific procedures were developed with input from the technical advisory committee. In Phase II, these procedures were used to evaluate retrofit costs at 12 plants based on data collected from site visits. Based on the results of this effort, simplified procedures were developed to estimate site-specific costs without conducting site visits. In Phase III, the simplified procedures were verified or modified based on utility input by visiting 6 of the 50 plants. The modified procedures were then used to estimate retrofit costs at the remaining 138 plants. In Phase IV, utility comments were incorporated into the final 200-plant study report.

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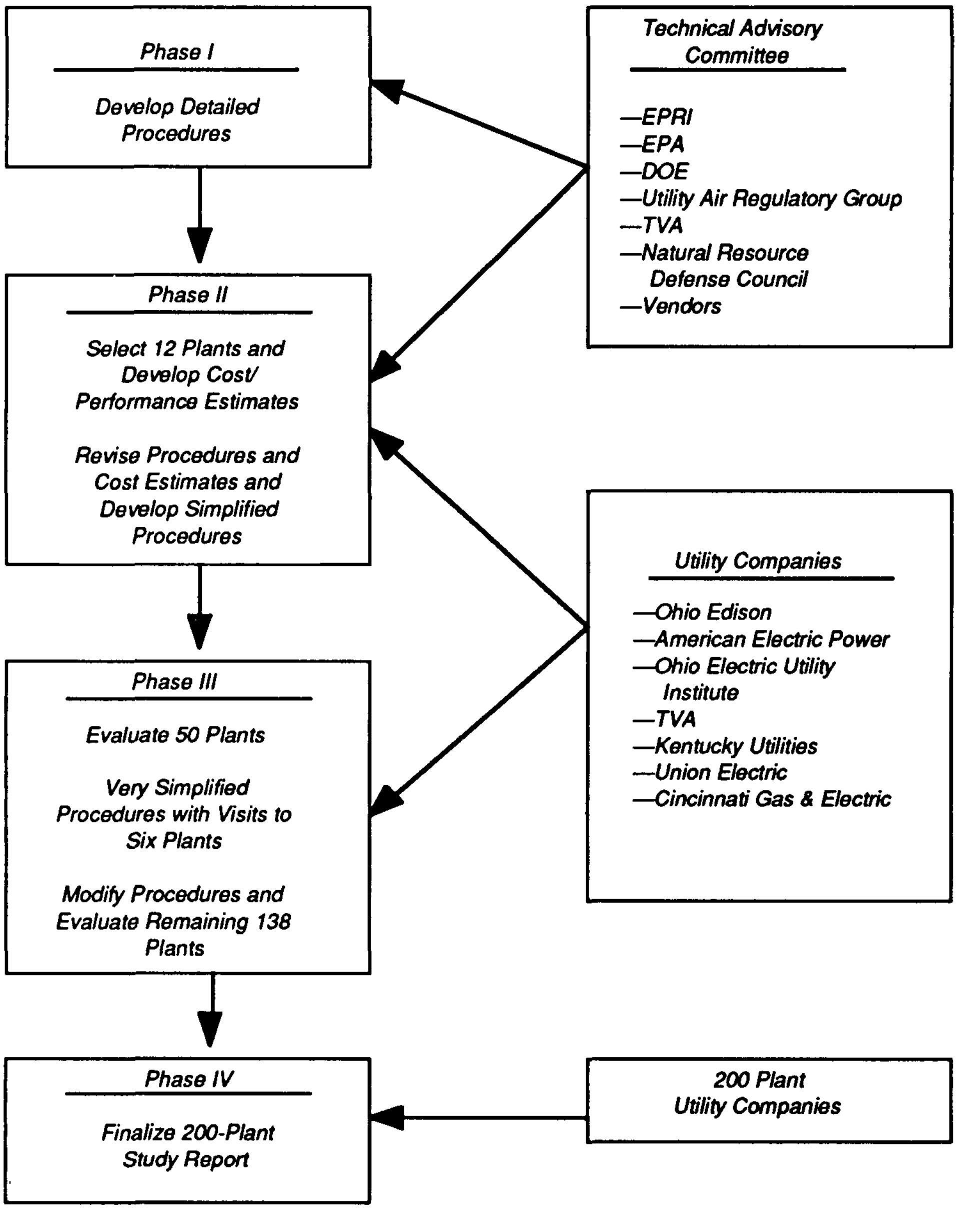


Figure 1. *200-Plant study technical approach.*

This report presents the cost estimates developed for 631 out of 662 boilers in 200 plants using the simplified procedures. Costs were not developed for 31 boilers because either they were burning fuels other than coal or they were new boilers with SO_2 and NO_x controls already installed. The commercial and developmental SO_2 and NO_x control technologies evaluated in the study are listed in Table 1. The detailed cost estimates developed for 55 boilers in the 12 plants evaluated using the detailed procedures are presented in another report. The cost results for all the boilers evaluated in this report are presented in a database file for further study and evaluation.

Methodology

For each plant, a boiler profile was completed using sources of public information, the primary source being the Energy Information Administration (EIA) Form 767. Additionally, boiler design data were obtained from generally available data bases, and aerial photographs were obtained from state and federal agencies. The plant and boiler profile information is used to develop the input data for ’’ performance and cost models. The pe mance and cost results incorporate . ommendations from utility companies and a technical advisory group. The advisory group included utility industry, flue gas desulfurization (FGD) vendor, and government agency representatives.

All of the cost estimates were developed using the Integrated Air Pollution Control System (IAPCS) cost model. The IAPCS model was upgraded to include all of the technologies being evaluated in this program. All of the cost estimates were developed using the integrated technologies evaluated in this program. Evaluated qualitatively without cost estimates were life extensions using fluidized bed combustion and coal gasification combined cycle.

Figure 2 presents the methodology used to develop IAPCS inputs to estimate site-specific costs of retrofitting SO_2 and NO_x controls. The site-specific information sources were used to develop process area retrofit multipliers, scope adder costs, and boiler and coal parameters. This information was input to the IAPCS cost model that generated the capital, operating and maintenance (O&M), and levelized annual costs of control and the emission reductions. The process area retrofit culty multipliers and scope adder c used to adjust generic cost model outp to reflect site-specific retrofit situations were derived from an Electric Power Research Institute (EPRI) report.

Table 2 summarizes the economic bases used to develop the cost estimates.

Summary of Cost Results

This section summarizes the site-specific control cost estimates developed for each boiler evaluated. The number of boilers varied for each control technology for reasons discussed under each control technology summary. For example, low NO_x burners were not evaluated on cyclone-fired boilers because this technology is not being developed for cyclone boilers (slagging combustors were not addressed under this study). For cyclone boilers and other wet bottom boilers, natural gas reburning (NGR) was evaluated for NO_x control.

For each control technology, the following three figures are presented: Capital costs (dollars/kilowatt), levelized annual costs (mills/kilowatt hour), and cost per ton of acid gas removed (dollars/ton), each plotted versus the sum of megawatts. The x-axis (sum of megawatts) is the cumula- tive sum of the boiler size sorted in (from the lowest to the highest co control. Also identified on each curve are 'e 1. *Emission Control Technologies Selected*

	Species Controlled		Development Status		
	SO_2	NO_x	Commercial	Limited Commercial Experience	Ongoing or Near Commercial Demonstration
Lime/Limestone (L/LS) flue gas desulfurization (FGD)	x		x		
Additive enhanced L/LS FGD	x		x		
Lime spray drying (LSD) FGD [a]	x		x		x
Physical coal cleaning (PCC)	x		x		
Coal switching and blending (CS/B)	x		x		
Low-No_x combustion (LNC)		x		x	
Furnace sorbent injection (FSI) with humidification	x				x
Duct spray drying (DSD)	x				x
Natural gas reburning (NGR) [b]	x	x			x
Selective catalytic reduction (SCR)		x		x	
Fluidized bed combustion (FBC) or coal gasification (CG) retrofit [c]	x	x		x	

[a]Commercial on low-sulfur coals, demonstrated at pilot scale on high-sulfur coals.
[b]For wet bottom boilers and other boilers where LNC is not applicable.
'uated qualitatively as combined life extension and SO_2 / NO_x control option. No costs were developed.

...s 25, 50, and 75 sum of megawatt percent points for the boilers included in the figure. Each point on the curve represents a specific boiler cost result. The first point represents the boiler that had the lowest capital cost and unit cost. The last point represents the boiler that had the highest cost. The curves turn up sharply because each curve was developed starting with the boiler having the lowest control cost and ending with the boiler having the highest control cost. The cost results do not represent the average or cumulative cost of control.

Each utility section in this report was sent to the appropriate utility for review concerning plant information. Costs developed in this report may not represent a particular utility company's economic guidelines. The cost results are static (not dynamic) and represent a single year in the 1986-1989 period with regard to capacity factor, coal sulfur, and pollution control characteristics.

FGD Cost Estimates

Figures 3 through 5 summarize the cost estimates developed for wet lime/limestone (L/LS) FGD with adipic acid ad- for 449 boilers. Two FGD configura- were evaluated: a conventional New Source Performance Standard (NSPS) design having a single system for each boiler, small absorber size, and one spare absorber; and a low-cost design that has combined boiler systems (when feasible), but not a spare absorber. The target SO_2 removal efficiency was 90%.

Cost estimates for FGD were developed for only 449 of 631 boilers because 46 boilers were already equipped with FGD systems, 130 boilers were burning low sulfur coals (many are 1971 NSPS units), and 6 boilers were too small or already retired. The percent increase in capital cost for retrofitting an FGD system over a typical new plant installation ranged from 19 to over 100%, with the average being 45%. The levelized annual cost of control (mills/kilowatt hour) is also strongly influenced by system size and design (e.g., percent reduction required or conventional versus low-cost configuration design), and operation (capacity factor and sorbent/waste disposal costs).

Figures 6 through 8 summarize the cost estimates for lime spray drying (LSD) for all the boilers for which costs were developed. Two control options were considered for the retrofit of this technology: reuse of the existing electrostatic precipitator (ESP) or installation of a new fabric filter (FF). Reuse of the existing ESP was not considered:

- when the specific collection area (SCA) of the existing ESP was small <43.3 m^2/actual m^3-sec or 220 ft^2/1000 acfm, and
- when the addition of new plate area was impractical (e.g., roof-mounted ESPs).

In such cases, a new FF was used for particulate control with the spray drying system. However, if a unit is burning high sulfur coal, use of a new FF was not considered. Based on the cited criteria, 168 boilers were considered with a new FF option, and 195 boilers were considered with reuse of the existing ESPs. The cost of retrofitting new FFs results in a high retrofit difficulty factor and a high cost of control.

Coal Switching and Cleaning

For coal switching (CS), two fuel price differentials (FPDs) were evaluated: $5 and $15/ton. The $5 to $15/ton FPD was assumed to represent an estimated range for switching to a low sulfur coal.

Figures 9 through 11 summarize the costs for 329 boilers in the 200 plants for which costs were developed for CS. The cost estimates for CS are based on $5 and $15/ton FPD. CS was not considered for some units because the units either

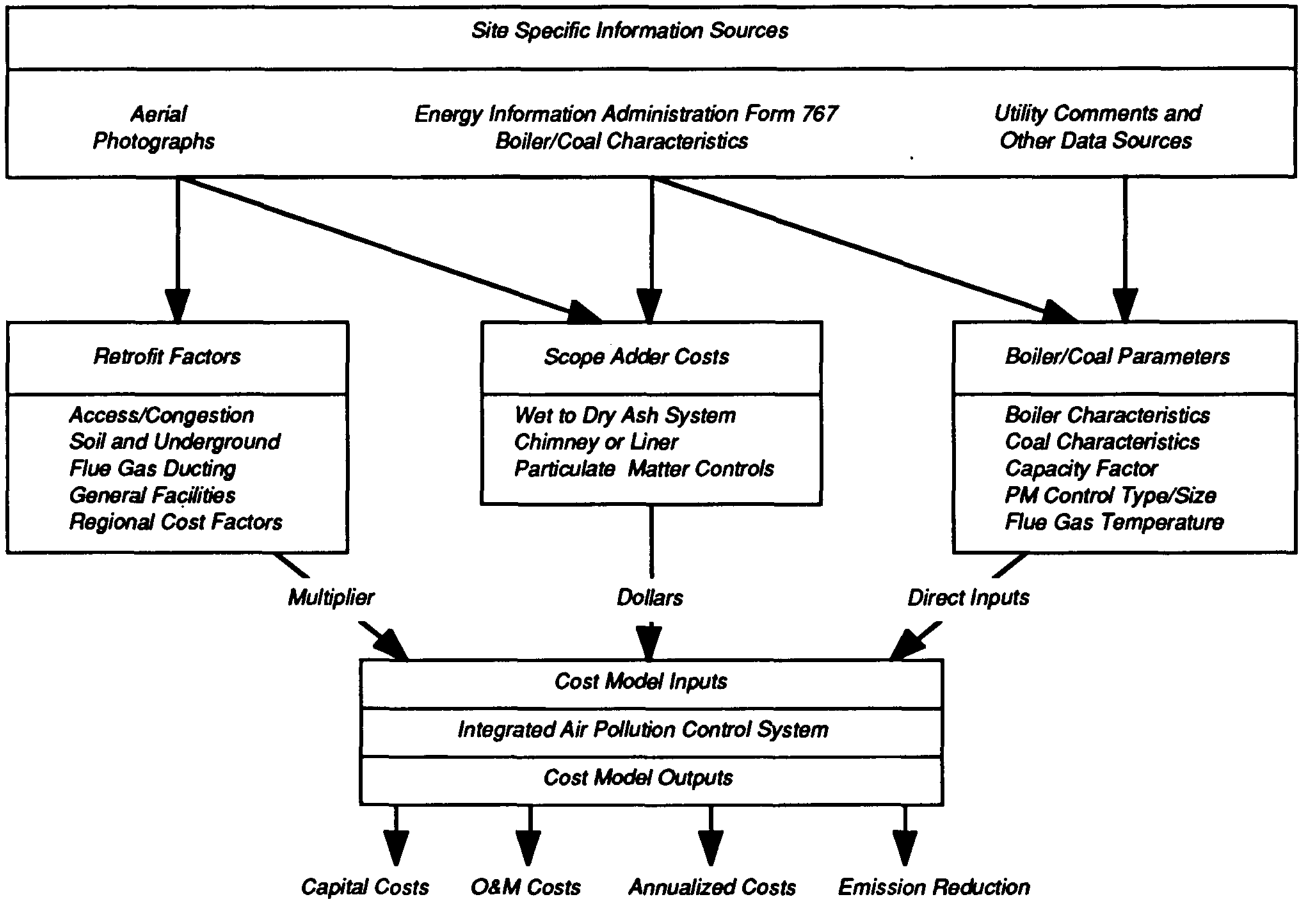


Figure 2. *Site-specific cost estimation methodology.*

Table 2. *Economic Bases Used to Develop the Cost Estimates*

Item	January 1985 Value	
Operating labor	19.7	$/person labor
Water	0.60	$/1000 gal.[a]
Lime	65	$/ton [a]
Limestone	15	$/ton
Land	6,500	$/acre [a]
Waste disposal	9.25	$/ton
Electric power	0.05	$/kWh
Catalyst cost	20,290	$/ton
Levelization factors	Current dollars [b]	Constant dollars [c]
Operating and maintenance	1.75	1.0
Carrying charges	17.5%	10.5%

[a]For readers more familiar with metric units: 1 gal. = 3.8 L, 1 ton = 907 kg, and 1 acre = 4047 m^2.
[b]Book life—30 years; tax life—20 years; depreciation method—straight line; and discount rate—12.5% based on a 6% escalation for inflation.
[c]Book life—30 years; tax life—20 years; depreciation method—straight line; and discount rate—6.1%.

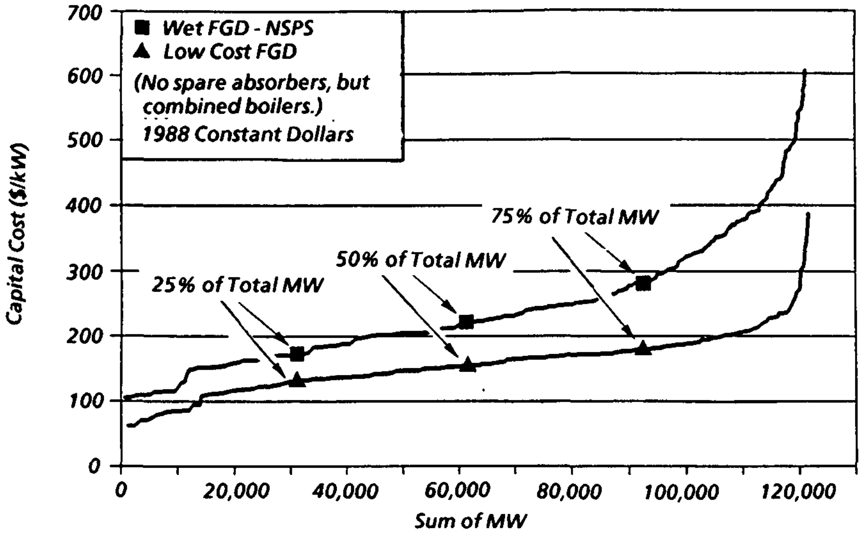


Figure 3. Summary of capital cost results for lime/limestone flue gas desulfurization.

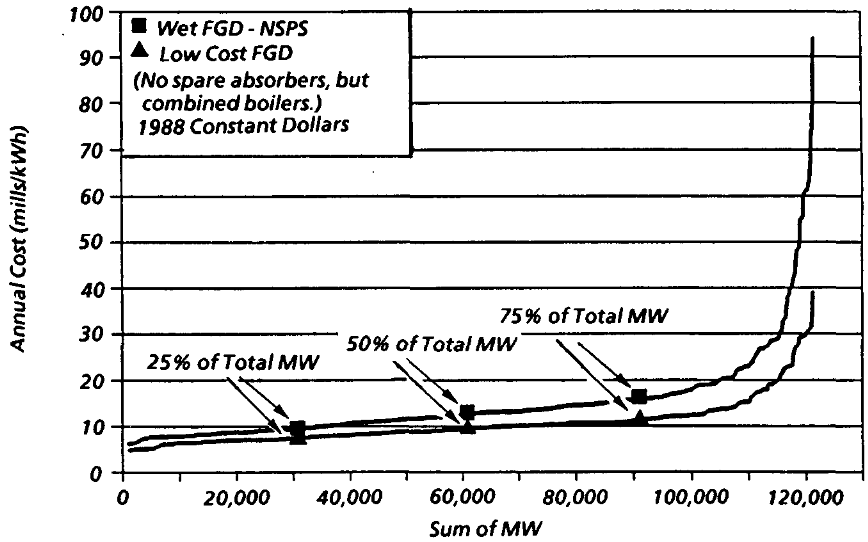


Figure 4. Summary of annual cost results for lime/limestone flue gas desulfurization.

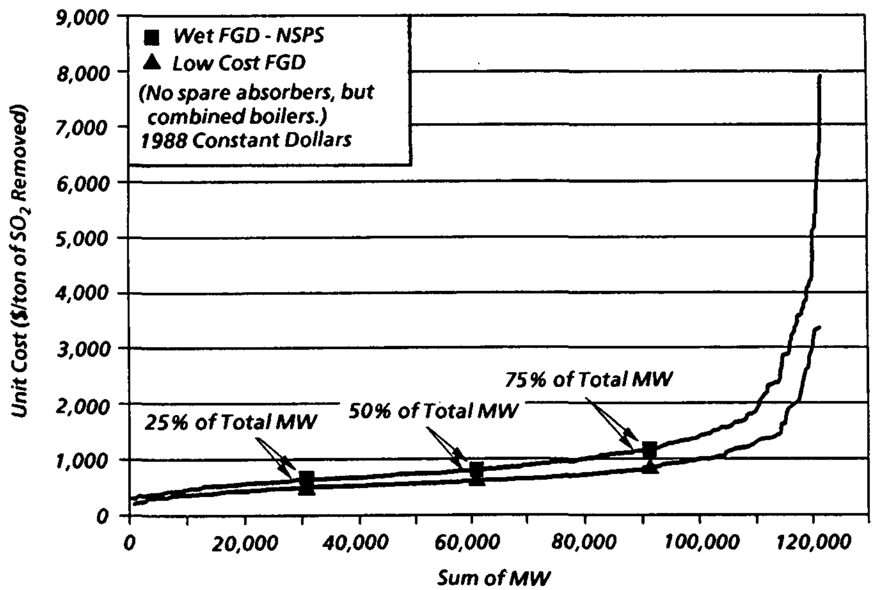


Figure 5. Summary of cost per ton of SO_2 removed results for lime/limestone flue gas desulfurization.

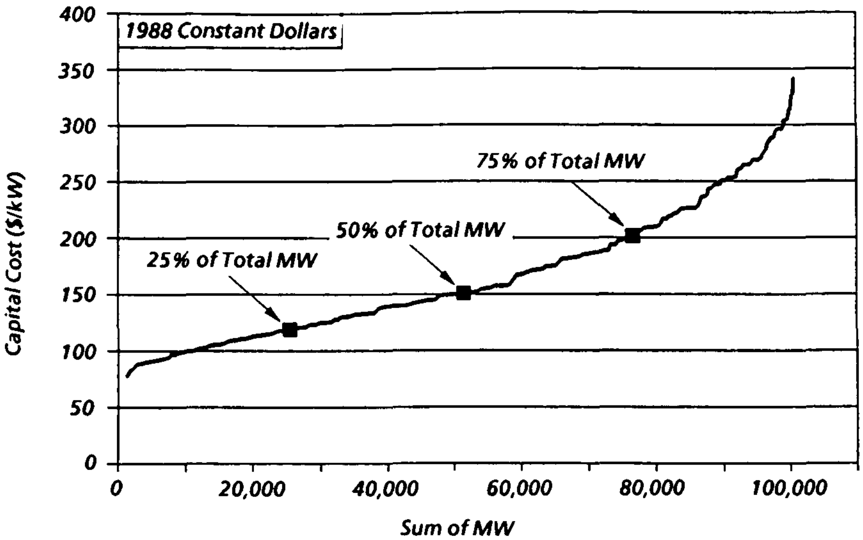


Figure 6. Summary of capital cost results for lime spray drying.

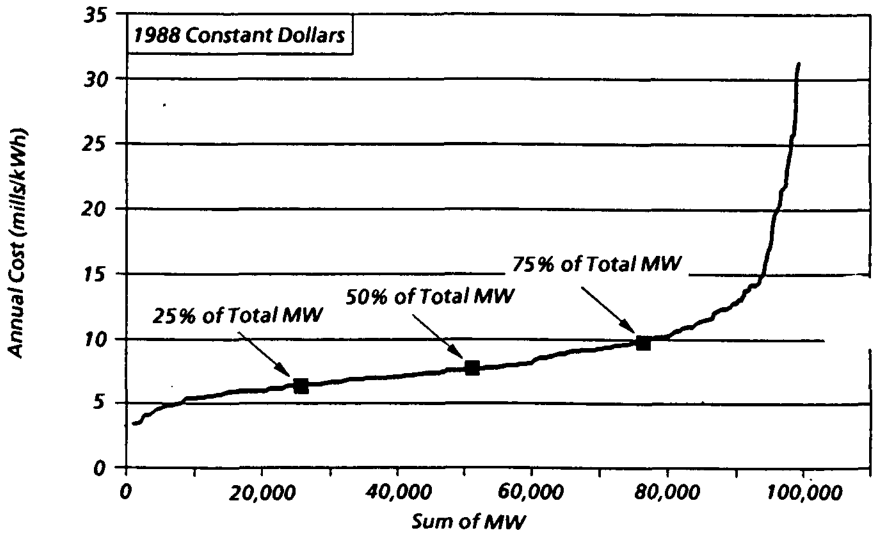


Figure 7. Summary of annual cost results for lime spray drying.

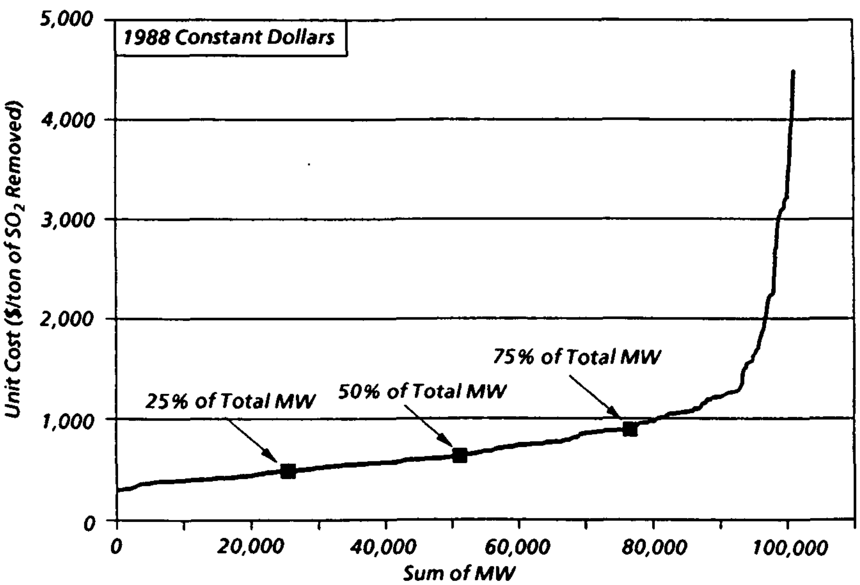


Figure 8. Summary of cost per ton of SO_2 removed results for lime spray drying.

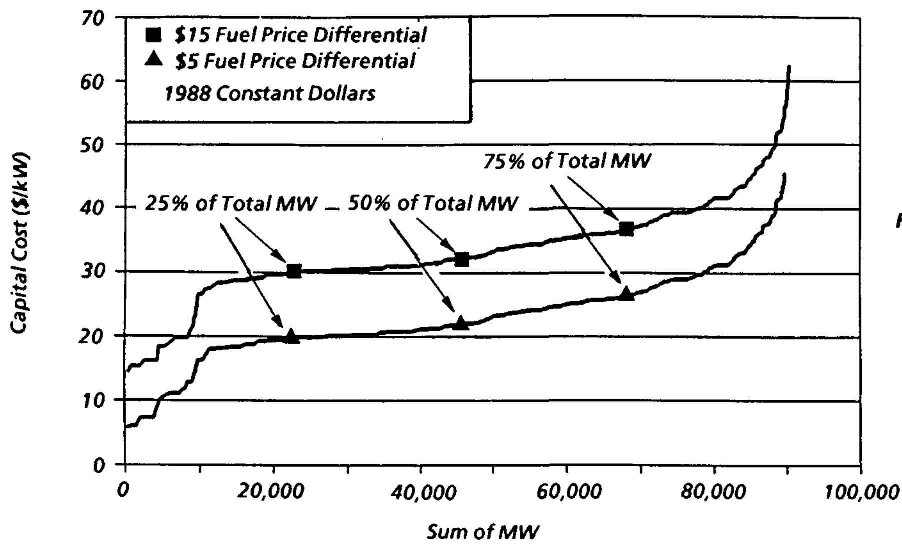


Figure 9. Summary of capital cost results for coal switching and blending.

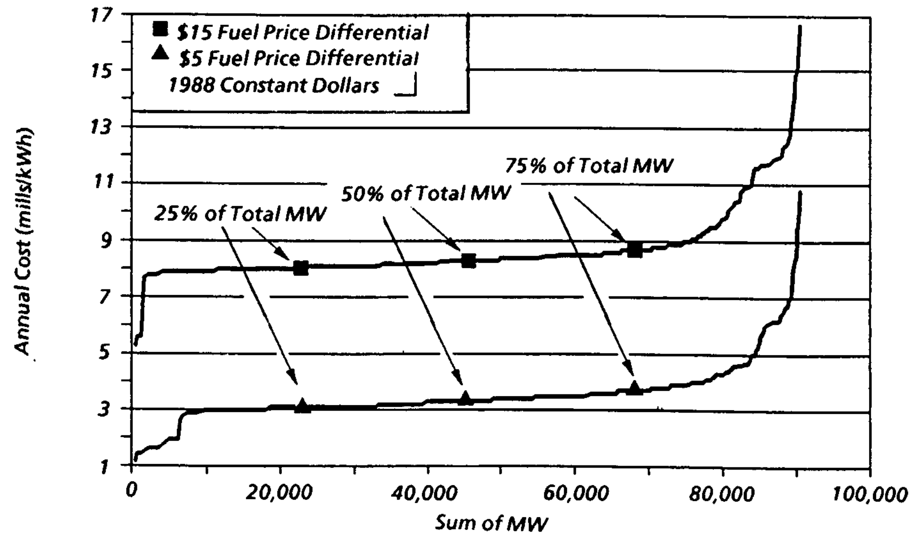


Figure 10. Summary of annual cost results for coal switching and blending.

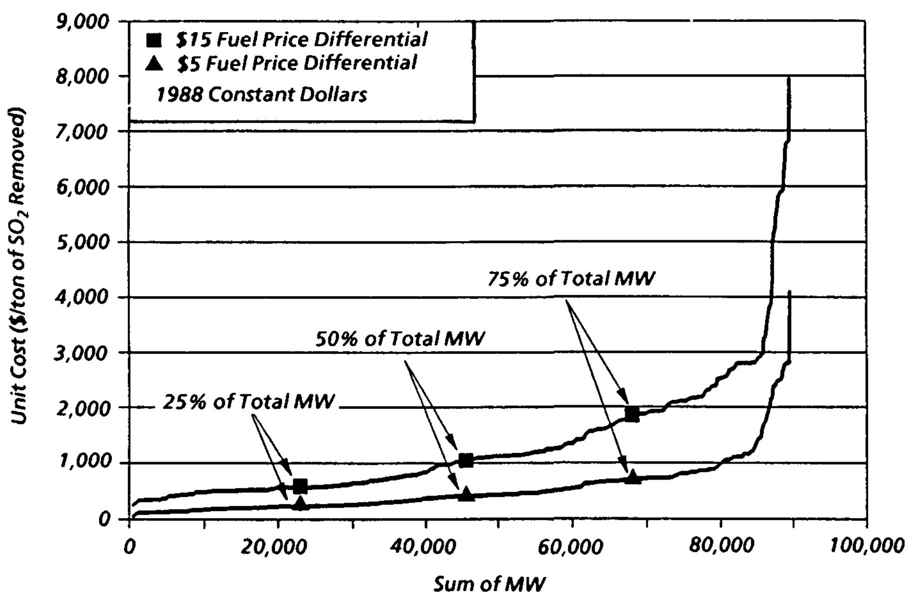


Figure 11. Summary of cost per ton of SO_2 removed results for coal switching and blending.

already burn a low sulfur coal or have wet-bottom boilers that can burn only coals with special ash fusion properties. The CS cost estimates are highly dependent upon the FPD. The impacts of particulate control upgrades and coal handling upgrades are generally small by comparison.

Figures 12 through 14 summarize the plant cost of physical coal cleaning (PCC). Of 631 boilers, only 32 were evaluated for PCC because either the coal already is extensively cleaned or the plant is not located at a mine mouth.

Sorbent Injection Cost and Performance Estimates

Two sorbent injection technologies in active research and development were evaluated in this study: furnace sorbent injection (FSI) with humidification and duct spray drying (DSD). Figures 15 through 20 summarize the cost estimates developed for these technologies. Some boilers were not considered good candidates for these technologies because:

- FSI and DSD were not considered practical for boilers having an ESP SCA < 220 ft^2/1000 acfm, and
- DSD was not considered if the duct residence time from the injection point after the air heater to the ESP inlet was less than 2 sec (<100 ft—30.5 m—of duct length).

Only 321 boilers were considered appropriate for DSD, and 289 were considered for FSI applications. The costs presented for FSI assume 50 and 70% SO_2 control with humidification.

Low NO_x Combustion

Figures 21 through 23 summarize cost estimates for application of low NO_x burner (LNB) on dry-bottom wall-fired boilers (20-55% NO_x reduction), overfire air (OFA) on tangential-fired boilers (10-35% NO_x reduction), and natural gas reburn (NGR) on cyclone boilers (60% NO_x reduction). The unit costs of LNB and OFA are low (<$300/ton of NO_x removed). However, for boilers where NGR is applied, the unit costs are much higher ($400-$1100/ton of NO_x removed). This is due to the high cost of natural gas relative to coal (assumed to be a $2 /$10^6$ Btu* fuel price differential in 1988 dollars). For this study, 228 boilers were candidates for LNB, 214 boilers for OFA, and 81 boilers for NGR. Some of the boilers were not considered for low NO_x combustion technologies (LNC) because of the reservations of plant personnel regarding applicability of these technologies.

Selective Catalytic Reduction (SCR) Cost Estimates

Figures 24 through 26 summarize the cost estimates for application of SCR. For most of the units, cold-side, tail-end systems were assumed (the reactor downstream of particulate control or scrubbers). In some instances, due to space availability limitations or the unit's being equipped with a hot-side ESP, a hot-side, high-dust system configuration was used (the reactor between the economizer and the air heater). Use of the tail-end system minimizes unit downtime, which reduces the uncertainty of estimating the cost of replacement power, and maximizes the catalyst life. However, a significant energy penalty is associated with flue gas reheating compared to that for a high-dust system (equivalent to a 120°F—49°C—reheat). This cost was not considered in this study because the current version of the IAPCS model is unable to estimate it. However, the cold-side SCR requires 60% of the hot-side catalyst volume. Based on a 1-year catalyst life, the reheat and extra catalyst volume costs offset each other. For this study, 624 boilers were evaluated for SCR retrofit.

Conclusion

For each SO_2 and NO_x control technology evaluated in this study, different factors affected control cost and performance estimates for retrofit applications at coal-fired boilers. Table 3 identifies factors found to have the most significant effects. For the L/LS-FGD technologies, site access/congestion and flue gas ducting distances were major factors. For LSD-FGD, the need to add new particulate control was also a major consideration.

For CS and PCC, the major retrofit factors, excluding FPD, were particulate control upgrade costs and boiler performance impacts. CS for wet-bottom boilers and switching from a bituminous to a subbituminous coal were not evaluated because boiler performance impacts are likely to be significant.

For the sorbent injection technologies, FSI and DSD, particulate control upgrade costs would have the greatest impact. Additionally, sufficient duct residence time must be available for DSD to guarantee good droplet drying.

For the LNC and NGR technologies, boiler type and configuration are important. LNB was applied only to dry-bottom, wall-fired boilers. OFA was applied only to tangential-fired units. NGR was applied wet-bottom boilers and other misc neous boiler types. Boiler heat rele rates and residence times in different furnace zones would have significant effects on NO_x removal efficiency for LNC and NGR technologies.

SCR costs would be greatly affected by access and congestion near the economizer area for hot-side applications. For cold-side applications, access and congestion near the chimney area and flue gas ducting distances greatly affect costs. For cold-side systems, the energy penalty for flue gas reheat is balanced by increased catalyst life and reduced catalyst costs. For hot-side systems, boiler downtime costs and catalyst life would be significant cost and performance factors.

The cost and performance information presented is a realistic guide regarding the degree of retrofit difficulty for each control option evaluated. However, as noted in Table 1, the technologies evaluated in this study are at various stages of commercial development. There is a higher degree of uncertainty regarding the cost/performance for those technologies that do not have extensive commercial application in the U.S. Therefore, no attempt has been made in this study to identify a best option for each plant/boiler.

Additionally, a utility company's dec concerning which retrofit control to ap to a given boiler is very complex. Considerations used in making such a decision include:

- system reduction target and degree of flexibility regarding means to achieve the target,
- current and future load pattern for each boiler with or without controls,
- cost of purchased power and planned new capacity,
- cost of capital and current/future financial strength, and
- public utility commission and state/regional regulatory agency attitudes.

The data contained in this report can be used to facilitate selection of least-cost control options for specific plants/boilers for planning scenarios that address the above decision criteria.

The cost results for all the technologies presented in this report are available in three DBase III+ files and can be obtained through the National Technical Information Service (NTIS). Disks 1 and 2 ar high density diskettes which contain: name, technology, boiler number, ca ity in megawatts, capacity factor, tons of

*For readers more familiar with metric units, 1 Btu = 1.054 kJ.

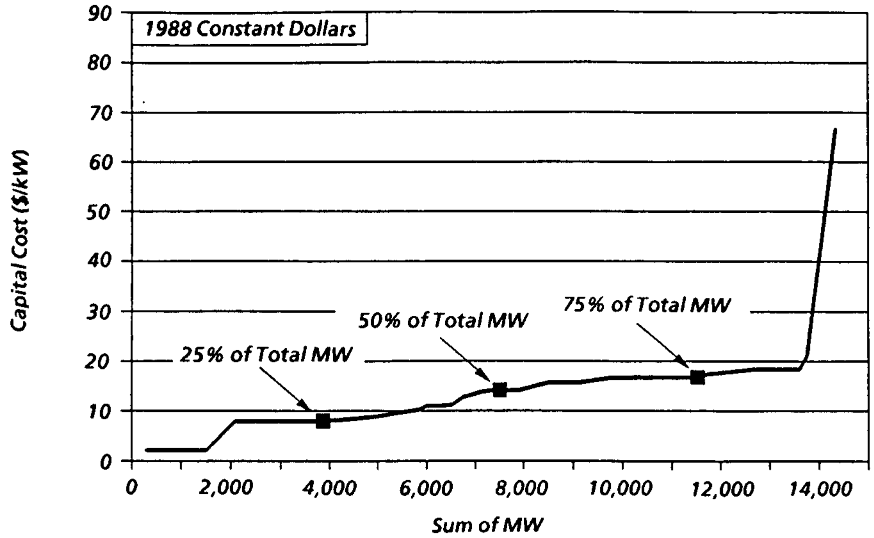


Figure 12. Summary of capital cost results for physical coal cleaning.

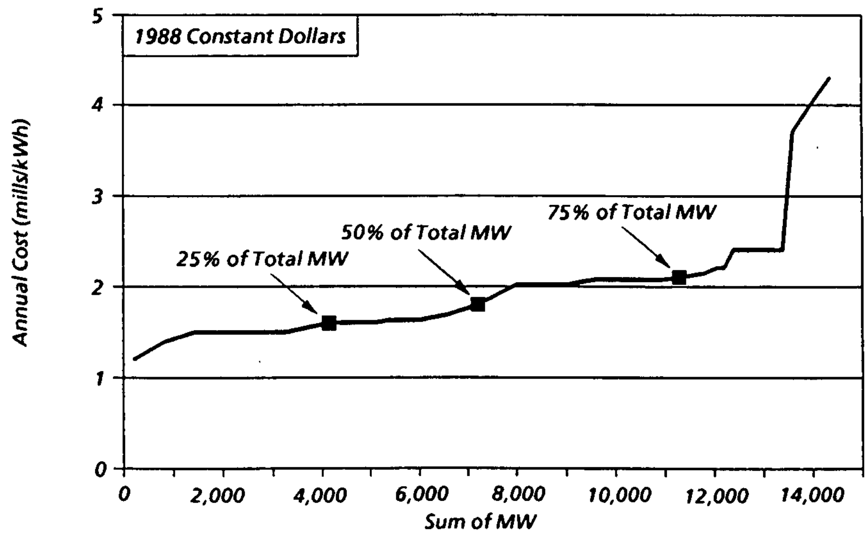


Figure 13. Summary of annual cost results for physical coal cleaning.

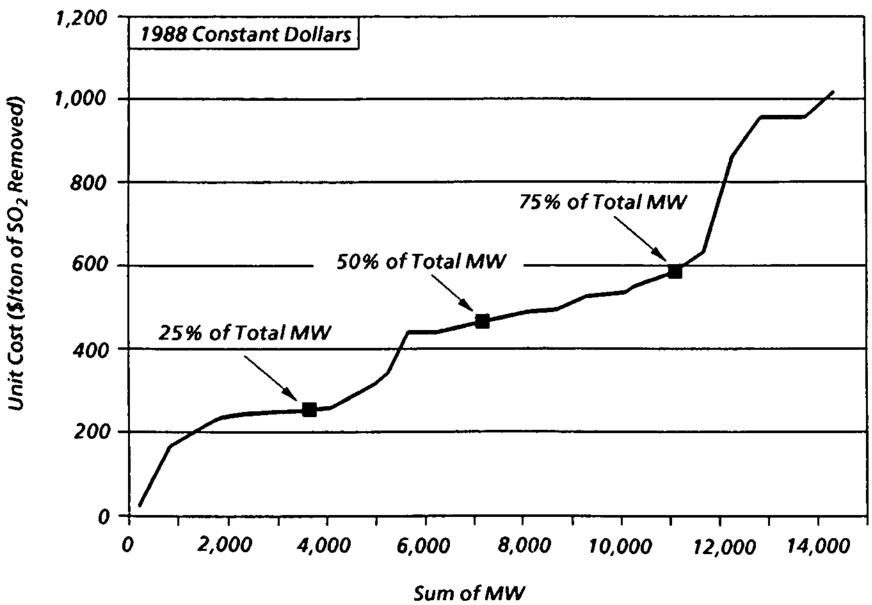


Figure 14. Summary of cost per ton of SO_2 removed results for physical coal cleaning.

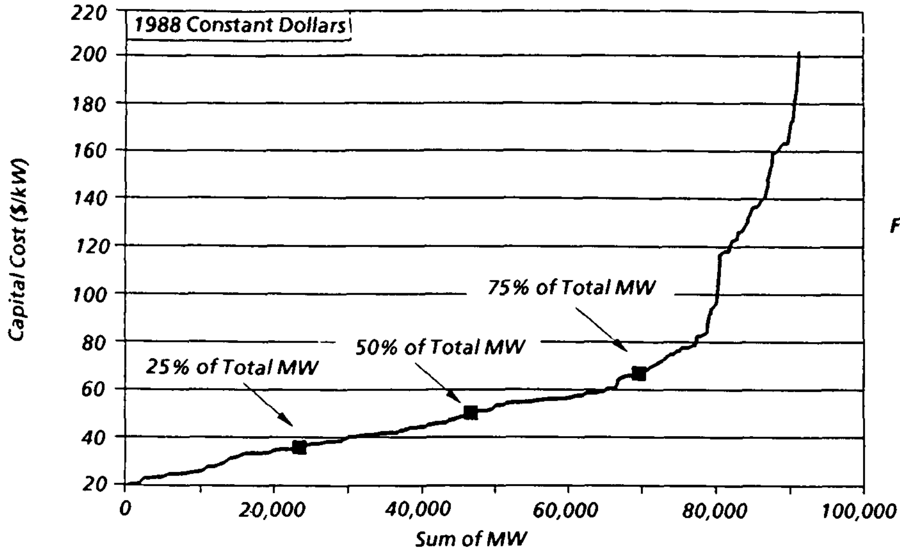


Figure 15. *Summary of capital cost results for duct spray drying.*

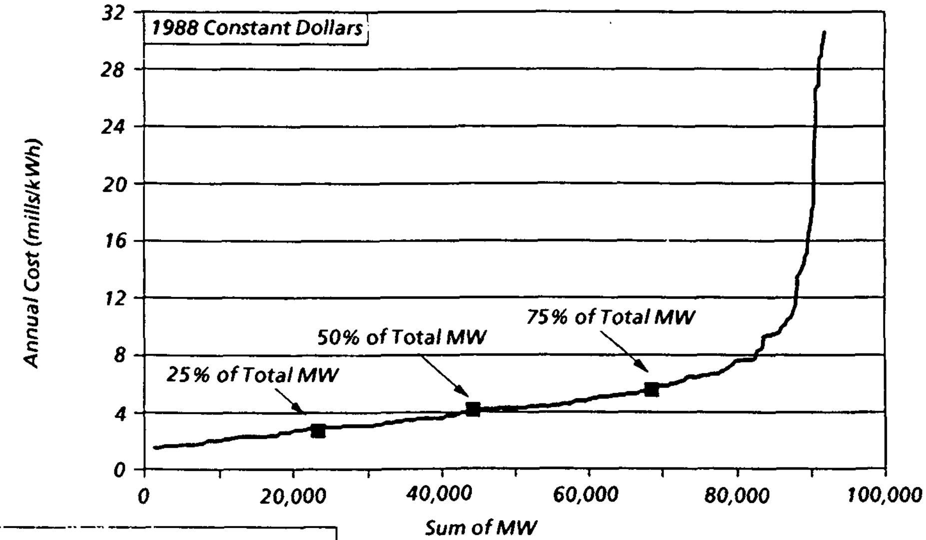


Figure 16. *Summary of annual cost results for duct spray drying.*

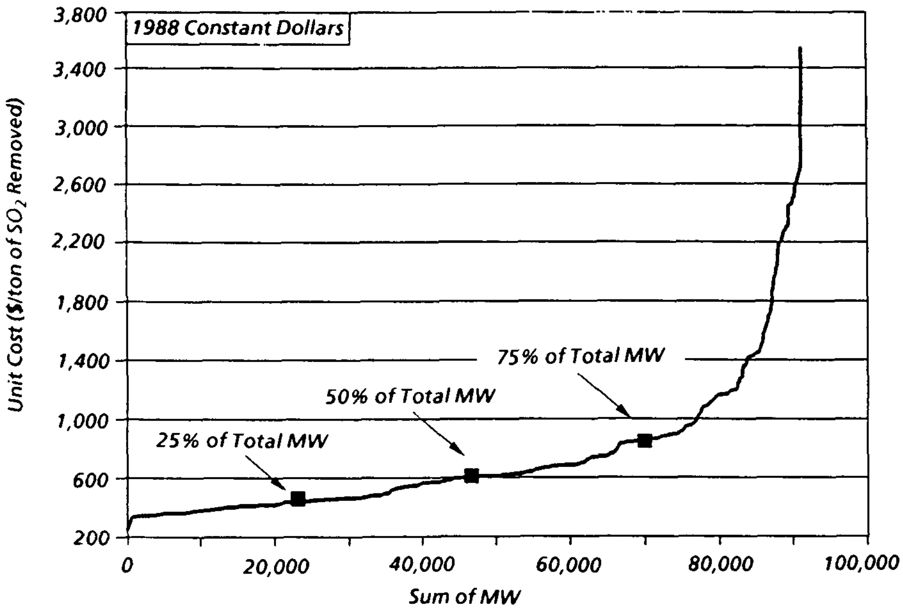


Figure 17. *Summary of cost per ton of SO_2 removed results for duct spray drying.*

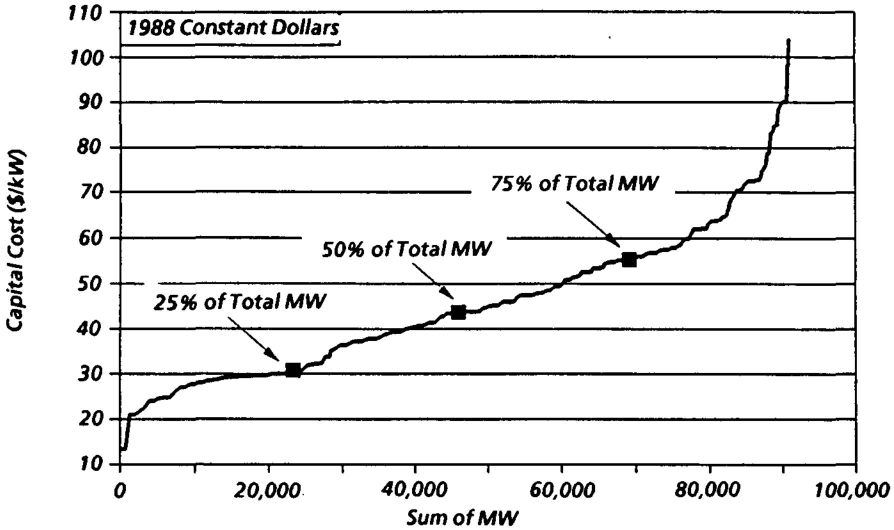
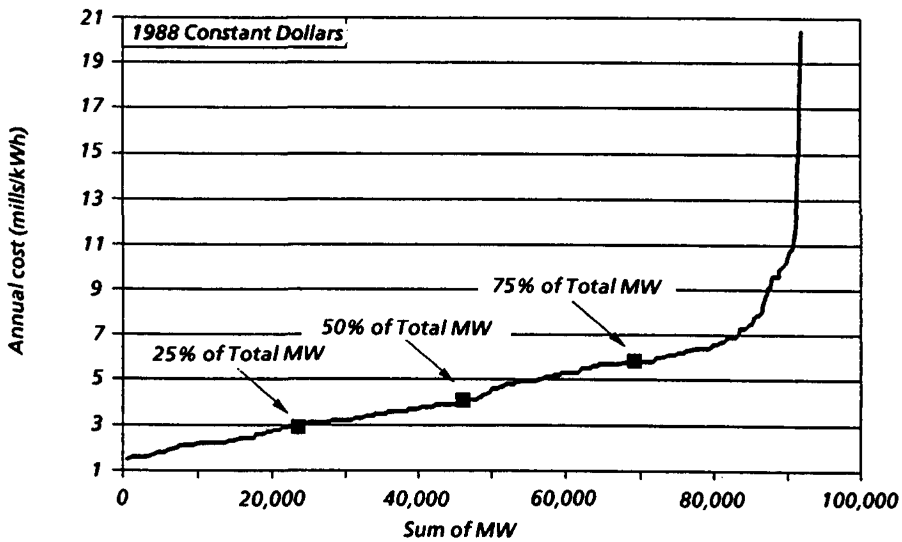


Figure 18. Summary of capital cost results for furnace sorbent injection.

Figure 19. Summary of annual cost results for furnace sorbent injection.



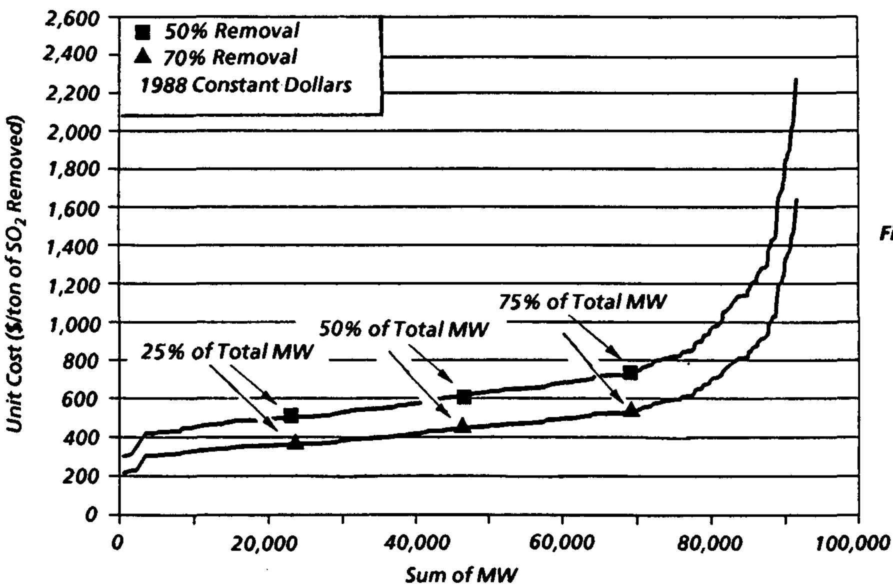


Figure 20. Summary of cost per ton of SO_2 removed results for furnace sorbent injection.

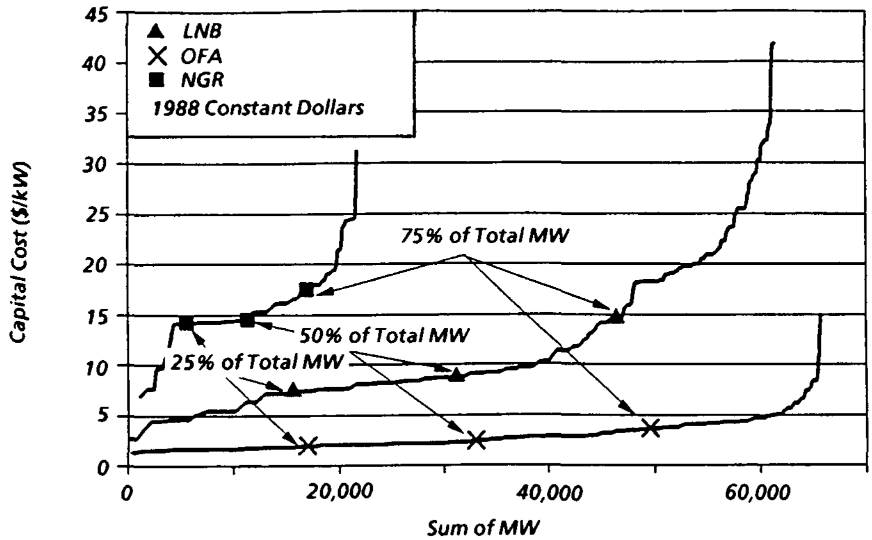


Figure 21. *Summary of capital cost results for low NO_x combustion.*

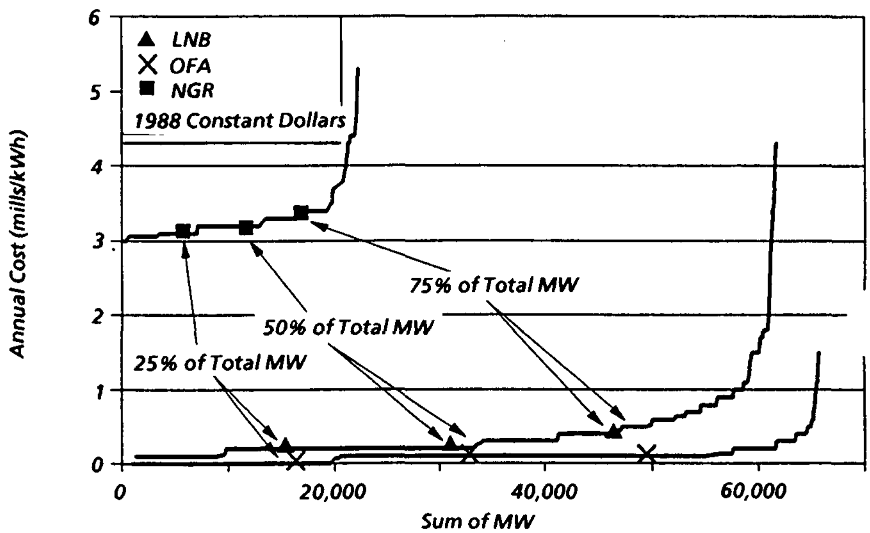


Figure 22. *Summary of annual cost results for low NO_x combustion.*

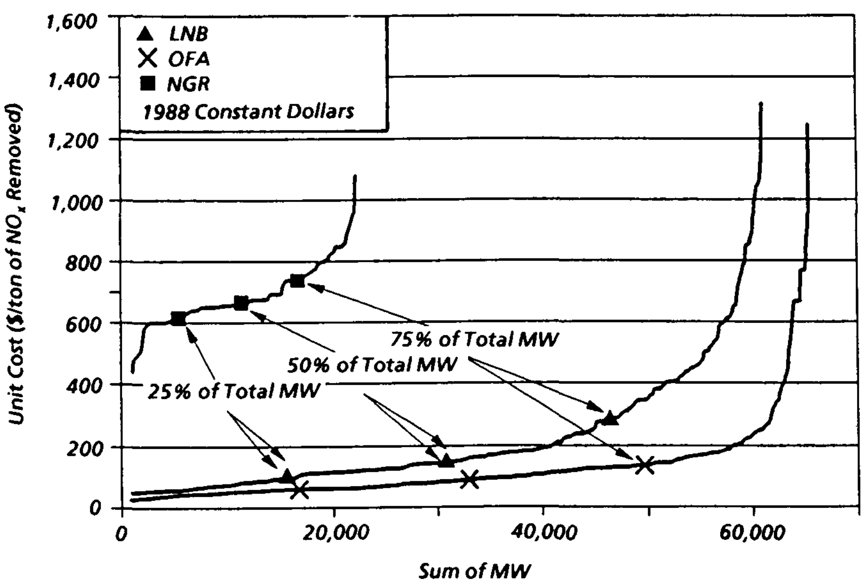


Figure 23. *Summary of cost per ton of NO_x removed results for low NO_x combustion.*

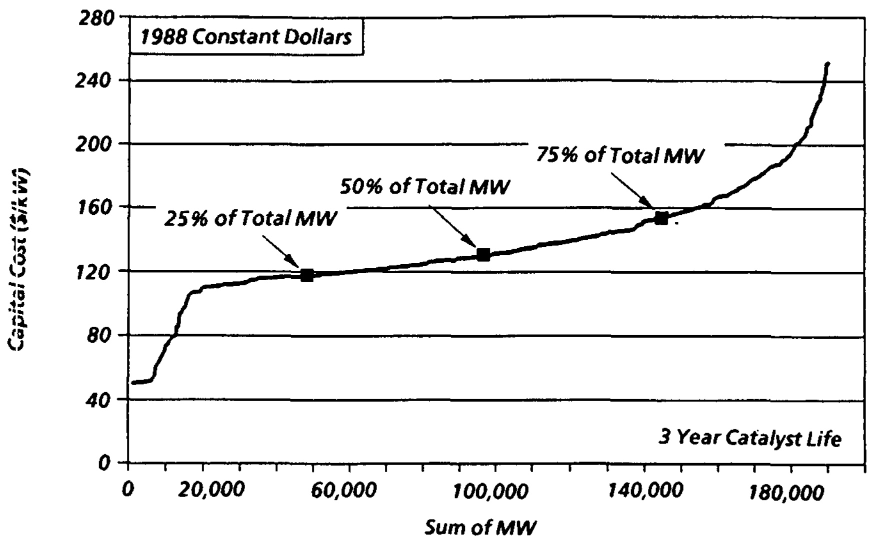


Figure 24. Summary of capital cost results for selective catalytic reduction.

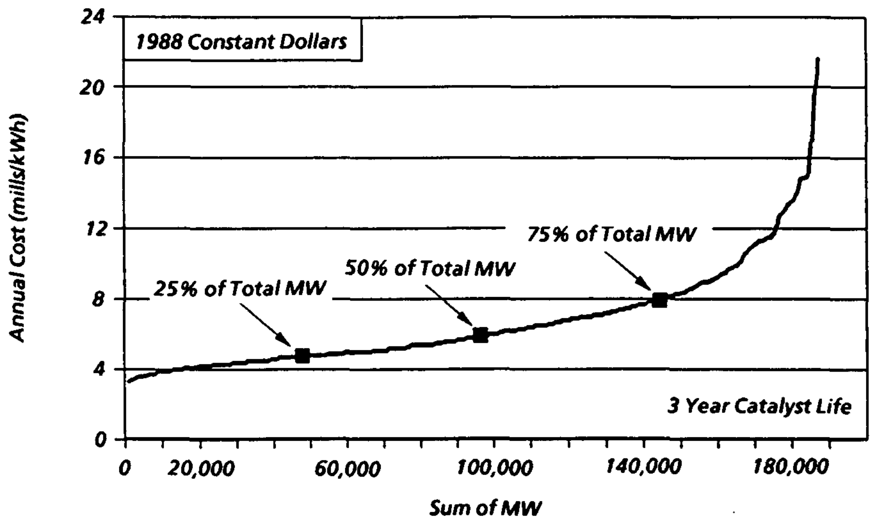


Figure 25. Summary of annual cost results for selective catalytic reduction.

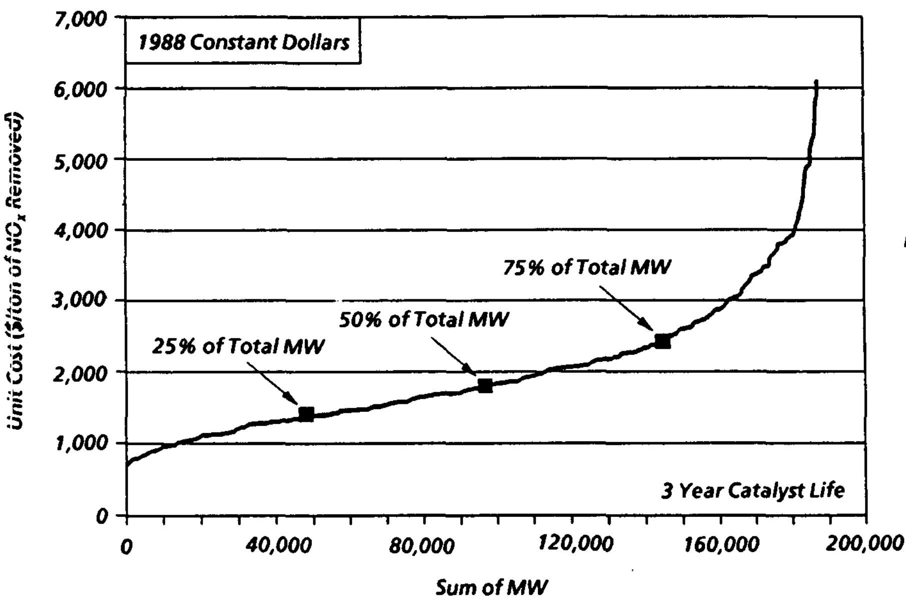


Figure 26. Summary of cost per ton of NO_x removed results for selective catalytic reduction.

Table 3. Retrofit Factors Affecting Cost/Performance

Control Technology	Access and Congestion	Ducting Distance	Additional Partticulate Control	Boiler Type	Boiler Configuration
Lime/Limestone Flue Gas Desulfurization	x	x			
Lime Spray Drying	x	x	x		
Coal Switching/Blending			x	x	
Physical Coal Cleaning			x	x	
Furnace Sorbent Injection			x		
Duct Spray Drying		x	x		
Low NO_x Combustion				x	x
Natural Gas Reburning				x	x
Selective Catalytic Reduction	x	x		x	

SO_2 and NO_x removed per year, SO_2 and NO_x removal efficiencies, capital cost in dollars, annual cost in dollars, dollars per kilowatt, mills per kilowatt hour, dollars per ton of SO_2 removed, and dollars per ton of NO_x removed. Disk 1 is in current 1988 dollars, disk 2 is in constant 1988 dollars, and disk 3 contains a third DBase file (200.DBF) with general plant, boiler, and company information based on Department of Energy Form 767 data. Disk 3 also contains an ASCII file (README.ASC) listing abbreviations used in all three database files. The cost result database can be used to estimate total costs and emissions for individual or combined control technologies for the 200 plants presented in this report.

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***Norman Kaplan** is the EPA Project Officer (see below).*
The complete report, consists of five volumes and diskettes entitled "Retrofit Costs for SO_2 and NO_x Control Options at 200 Coal-Fired Plants," (Set Order No. PB 91-133 314/AS; Cost $181.50, subject to change).
"Volume I. Introduction and Methodology" (Order No. PB 91-133 322/AS; Cost: $17.00, subject to change).
"Volume II. Site-Specific Studies for AL, DE, FL, GA, IL" (Order No. PB 91-133 330/AS; Cost: $45.00, subject to change).
"Volume III. Site Specific Studies for IN, KY, MA, MD, MI, MN" (Order No. PB 91-133 348/AS; Cost: $45.00, subject to change).
"Volume IV. Site Specific Studies for MO, MS, NC, NH, NJ, NY, OH" (Order No. PB 91-133 355/AS; Cost: $53.00, subject to change).
"Volume V. Site Specific Studies for PA, SC, TN, VA, WI, WV" (Order No. PB 91-133 363/AS; Cost: $53.00, subject to change).
Related set of three diskettes (Order No. PB 91-506 295/AS; Cost $80.00 subject to change).
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5285 Port Royal Road
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