United States
Environmental Protection
Agency

Air and Energy Engineering
Research Laboratory
Research Triangle Park, NC 27711

Research and Development

EPA/600/S7-90/018 Jan. 1991

EPA

Project Summary

Assessment of Control Technologies for Reducing Emissions of SO_2 and NO_x from Existing Coal-Fired Utility Boilers

David M. White and Mehdi Maibodi

A major objective of the National Acid Precipitation Assessment Program is to evaluate alternative methods for reducing SO_2 and NO_x emissions from combustion sources and to identify options which appear most promising from both an emissions reduction and cost standpoint. Part of this overall effort is to develop up-to-date generic assessments of commercial, near-commercial, and emerging emission control technologies applicable to existing coal-fired electric utility boilers. This report reviews available information and estimated costs on 15 technology categories, including passive controls such as least emission dispatching, conventional processes, and emerging technologies still undergoing pilot scale and commercial demonstration.

The status of each technology is reviewed relative to four elements:

- **Description – how does the technology work?**
- **Applicability – how does it apply to existing plants?**
- **Performance – what is the expected emissions reduction?**
- **Cost – what is the capital cost, busbar cost, and cost per ton of SO_2 and NO_x removed?**

Cost estimates are presented for new and retrofit applications for various boiler sizes, operating characteristics, fuel qualities, and boiler retrofit difficulties. Capital costs vary from \$2/kW for Overfire Air to \$2,800/kW for Integrated Gasification Combined Cycle in 1988 dollars.

This Project Summary was developed by EPA's Air and Energy Engineering 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).

Background and Purpose

One of the objectives of the National Acid Precipitation Assessment Program (NAPAP) is to evaluate the potential performance and cost of alternative methods for reducing SO_2 and NO_x emissions from combustion sources. Part of this overall effort is to develop up-to-date generic information on commercial, near-commercial, and emerging emission control technologies applicable to coal-fired electric utility boilers. This report reviews available information on the technologies shown on Table 1. Because the various acid rain regulatory proposals focus on reduction of SO_2 and NO_x in the eastern half of the U.S., the report focuses on each technology's potential for retrofit onto existing boilers in the eastern U. S. burning medium- and high-sulfur coals.

Organization

The technology reviews are divided into three major sections covering technologies which are commercial, near-commercial, and emerging. These three classes are respectively defined as follows: technologies routinely used by U. S. electric utilities, technologies undergoing large-scale demonstration by U. S.

Table 1. Control Technologies Reviewed

Technology	Potential Emission Reductions (%) SO_2	NO_x
Commercial		
Fuel Switching and Blending	50-80	0-10
Least Emissions Dispatch	0-90	0-40
Physical Coal Cleaning	20-50	0
Low NO_x Burners	0	30-50
Overfire Air	0	15-30
Lime/Limestone FGD[a]	90-95	0
Additive Enhanced FGD	90-95	0
Dual Alkali FGD	90-95	0
By-Product Recovery FGD	90-95	0
Spray Drying	70-90	0*
Near Commercial		
Integrated Gasification Combined Cycle	90-95	90-95
Fluidized Bed Combustion	80-90	>50
Selective Catalytic Reduction	0	80-90
Furnace Sorbent Injection	50-70	0
Low-Temperature Sorbent Injection	50-70	0
Reburning	15-20	35-50
Emerging		
Advanced Coal Cleaning	45-60	0
Electron Beam Irradiation	80-95	55-90
Copper Oxide FGD	90-95	90-95

[a] *Flue Gas Desulfurization.*

utilities or commercially used in Japan or Europe, and those still undergoing laboratory or pilot-scale testing. Designation of a technology to one of these three classes is based on the technology's demonstrated status on low and high sulfur coals.

Within each major section, the technologies are presented in the following order: passive controls, precombustion controls, combustion controls, post-combustion controls, and combined systems. The term "passive controls" refers to technologies which in many cases require little or no capital expenditure (i.e., hardware) but which will require changes in a utility's operating methods. The status of each technology is reviewed relative to four elements:

- Description – how does the technology work?
- Applicability – How does it apply to existing plants burning low- and high-sulfur coals?
- Performance – what is the expected emissions reduction?
- Cost – what are the capital cost, busbar cost, and cost per ton of SO_2 and NO_x removed?

Because of the importance of consistent treatment of each technology, consistent economic procedures were used for most technologies to allow comparisons. The methodology used for this purpose is discussed below.

Methodology

Because of the diversity of plant sizes and designs, operating characteristics, fuel quality, and financing arrangements found throughout U. S. utilities, it was necessary to define a uniform methodology for use in the report. These procedures can be divided into two major categories: boiler design and economic assumptions. Base case, high, and low values were selected for boiler design and economic parameters. The range in values was evaluated to present boiler conditions which may favor the selection of one technology option over another. Table 2 presents the boiler design and economic assumptions selected.

For the technologies addressed in this report, order of magnitude cost estimates are presented. The cost estimates presented in the text are based on a range of boiler and coal parameters. The cost of many technologies is site-specific and varies significantly depending on the boiler and coal characteristics.

The Integrated Air Pollution Control Systems (IAPCS) cost model, which is currently being updated to include more technologies, was used to develop the cost estimates for some of the technologies in this report. The cost/performance assumptions are the same as used under the NAPAP site-specific retrofit cost study under which the costs of retrofitting SO_2 and NO_x controls at 200 coal-fired utility power plants are being estimated. The IAPCS cost model was used to develop cost estimates for the following control technologies:

- Coal switching and blending (CS/B),
- Furnace sorbent injection (FSI),
- Lime spray drying with reuse of the existing electrostatic precipitators (LSD+ESP),
- Lime spray drying with a new fabric filter (LSD+FF),
- Lime/limestone FGD (L/LS FGD),
- Natural gas reburn (NGR),
- Low NO_x burner (LNB),
- Overfire air (OFA),
- Selective catalytic reduction (SCR),
- Integrated gasification combined cycle (IGCC), and
- Atmospheric fluidized bed combustion (AFBC).

For the other technologies addressed in this report, costs are from referenced publications. These costs are not included in this section for comparison, since other cost model assumptions were used in generating costs which may not be consistent with assumptions used in the IAPCS cost estimates.

Economic Assumptions

Cost estimates are presented in 1988 dollars using both current and constant dollar procedures. The Electric Power Research Institute's (EPRI's) general costing procedures were used to incorporate inflation, cost of capital, and levelization of future expenses. The cost of replacement power or lost capacity while a plant is out-of-service during retrofit is not included in the analysis. Downtime replacement power costs depend on the duration of the downtime period and the difference between the cost of purchased or replaced electricity and that of power generated by the out-of-service unit. For example, assuming a power cost differential of 10 mills /kWh for three different downtime periods of 1, 3, and 6 months with a capacity factor of 50 percent, the following additional capital investments would be required:

Downtime Period	*Downtime Replacement Power Costs*
(Months)	*($/kW)*
1	*4*
3	*11*
6	*22*

Table 2. Bases for Cost Estimates

Parameter Descriptions	*Base Case Value*	*High Case Value*	*Low Case Value*
	Boiler and Coal Characteristic Assumptions		
Unit			
Size, MW	*300*	*100*	*700*
Capacity factor, %	*50*	*10*	*90*
Specific collection area (SCA), ft²/1000 acfm[a]	*300*	*200*	*400*
Coal Characteristics			
Sulfur content, %	*2.0*	*1.0*	*4.0*
Switched fuel sulfur content, %	*0.9*	*0.9*	*0.9*
Ash content, %	*10.0*	*5.0*	*15.0*
High heating value, Btu/lb	*11,000*	*9,000*	*13,000*
	Economic Assumptions		
Capital Cost Indirects			
General facilities, %	*10%*		
Engineering, %	*10%*		
Project contingencies, %	*30%*		
Process contingencies, %	*0-10%, commercial technologies* *10-30%, developing technologies*		
Retrofit factor (for FGD or SCR)	*1.3*	*1.5*	*1.0*
Economic Life	*20*	*15*	*30*
Carrying Charge Factor	*0.189*	*0.205*	*0.175*
O&M Levelizing Factor	*1.57*	*1.45*	*1.75*
Operating Costs			
Fuel price differential, $/ton	*10*	*15*	*5*
Operating labor, $/hr	*21.4*		
Steam, $/1000 lb	*7.0*		
Electricity, mills/kWh	*57.0*		
Lime, $/ton	*60.0*		
Limestone, $/ton	*16.0*		
Organic acid, $/ton	*1,725.0*		
Ammonia, $/ton	*150.0*		
SCR catalyst, $/ton	*20,300.0*		
Waste disposal, $/ton	*10.0*		
Water, $/1000 gal	*0.65*		
Natural gas, $/10⁶Btu	*2.0*		
Sulfur, $/ton	*65.0*		

[a] *Readers more familiar with metric units may use the factors at the end of this Summary to convert to that system.*

The new coal-fired plant cost of power would be approximately 60 mills/kWh: half the cost would be fixed cost and the remainder, fuel and consumable costs.

For post combustion technologies the downtime replacement power cost is less of a factor than for in-situ technologies. Constant dollar calculations are based on standard return on investment (i.e., annuity) calculations without consideration of tax incentives (e.g., accelerated depreciation, investment tax credits) or allowance for funds used during construction (AFDC). The cost calculations include a state and federal income tax rate of 38%.

The costs presented in the appendices are in current 1988 dollars and a 30-year book life. To approximate the total levelized busbar cost of power in constant dollars, divide the current dollar costs by 1.75.

Summary of Results

Table 3 and Figures 1-3 summarize for each technology the range of cost estimates developed in Table 2 using the high and low case values. The most representative value, the base case, is shown on the figures for each technology as a mid-way point on the bar graphs. This is to show the technology sensitivity to variation in boiler and coal characteristics and that there is no single "winner" for all retrofit applications.

Only those costs which were developed using the IAPCS cost model were presented in this section for consistency. Cost estimates for other technologies which were obtained from other references are presented in the respective technology sections.

Sensitivity case cost estimates developed using the IAPCS cost model are also presented in the appendices. The major cost parameters were varied for the sensitivity analysis. Major cost parameters differ for the different technologies. For example, FGD costs are very sensitive to retrofit factors, coal sulfur content, capacity factor, and boiler size, while coal switching is mainly a function of fuel price differential and percent reduction required. Sensitivity case parameters for different technologies are listed in Table 3.

Figures 1-3 present cost estimates for both low and high cases for capital, levelized annual, and unit costs. Costs as well as pollutant removal efficiencies vary for different technologies. These two factors should be balanced in choosing one technology over another and determining the cheapest technology for meeting acid gas removal requirements for a given boiler and coal characteristics.

In this study both high and low sulfur coals are switched to a 0.9% West Virginia bituminous coal. Therefore, for high sulfur coal (low case) over 80% SO_2 removal is achieved, while for low sulfur coal (high case) the removal value is less than 10%. Because of a very low removal efficiency due to switching from one low sulfur coal to another low sulfur coal with less than 10% SO_2 removal, the unit cost (dollar per ton of SO_2 removed) resulted in a very large number (the division denominator was a very small value for tons of SO_2 removal). The AFBC and IGCC costs presented are for new systems. The costs for these two technologies are much higher than for other presented technologies because pulverized coal boiler costs (equivalent to AFBC and IGCC) are not included with the other technologies. For FSI, it is assumed that 70% SO_2 removal can be achieved with humidification and that existing ESPs are adequate in size and can be reused. Therefore the major cost items are sorbent preparation and modification of the existing furnace for sorbent injection.

SCR costs are much greater than other NO_x removal technologies. This is mainly due to the initial as well as the replaced catalyst cost. However, unlike other NO_x removal technologies, SCR can achieve more than 80% NO_x removal.

Metric Equivalents

Readers more familiar with metric units may use the following factors to convert to that system:

British	Multiplied by	Yields Metric
Btu	1.055	kJ
Btu/lb	2.326	kJ/kg
ft^2/1000 acfm (SCA)	197	m^2/1000 am^3/s
gal.	0.00379	m^3
lb	0.454	kg
ton	907	kg

Table 3. *Summary of Cost Results — Constant 1988 Dollars*

Technology	Emission Reduction Percent		Capital Costs ($/kW)			Levelized Annual Costs mills/kWh)			Costs Per Unit of Pollutant Removed ($/ton)			Most Sensitive Parameters
	SO_2	NO_X	Low	Base	High	Low	Base	High	Low	Base	High	
Commercial												
Fuel Switching and Blending	2-80	0	20	28	30	3	6	13	350	600	24,000	% S, CF, FPD, SCA
Lime/Limestone FGD	90	0	120	240	520	5	16	150	800	980	3,600	MW, RF, CF, %S
Lime Spray Drying with Reuse of existing ESP	76	0	70	170	540	3	10	130	550	750	4,000	MW, RF, CF, %S, SCA
Lime Spray Drying with New fabric filter	86	0	140	240	620	5	13	150	730	850	4,000	MW, RF, CF, %S
Low NO_x Burners	0	50	8	13	25	<1	<1	5	60	190	1,600	% Reduction
Overfire Air	0	25	2	3	6	<1	<1	1	40	130	1,050	MW, CF, % Reduction
Near Commercial												
Advanced Combustion Systems												
Integrated Gasification Combined Cycle[a]	95	60-70	1,710	2,100	2,800	44	91	605	—	—	—	MW, CF, heat rate
Atmospheric Fluidized Bed Combustion[a]	90	20-50	1,360	1,680	2,250	40	80	480	—	—	—	MW, CF, heat rate
Add-on Controls												
Furnace Sorbent Injection	70	0	25	50	110	2	6	40	390	460	1,220	MW, CF, %S, SCA
Natural Gas Reburn	15	60	10	18	28	2	4	9	730	1,400	2,600	FPD
Selective Catalytic Reduction	0	80	90	130	190	3	8	70	950	2,100	14,000	RF, MW, CF, Catalyst life

MW - Size in megawatts.
%S - Coal sulfur content.
CF - Capacity factor.
SCA - Specific collection area of ESP.
FPD - Fuel price differential.
RF - Retrofit factor.
a - Greenfield plant costs. Repowered plant costs would be 10-20% lower in capital cost for IGCC and 25-40% lower in capital cost for AFBC. IGCC repowered plant/unit size would be 2-3 times larger than the existing plant/unit size when the repowered plant/unit is sized based on reuse of the existing steam turbine for combined cycle power generation.

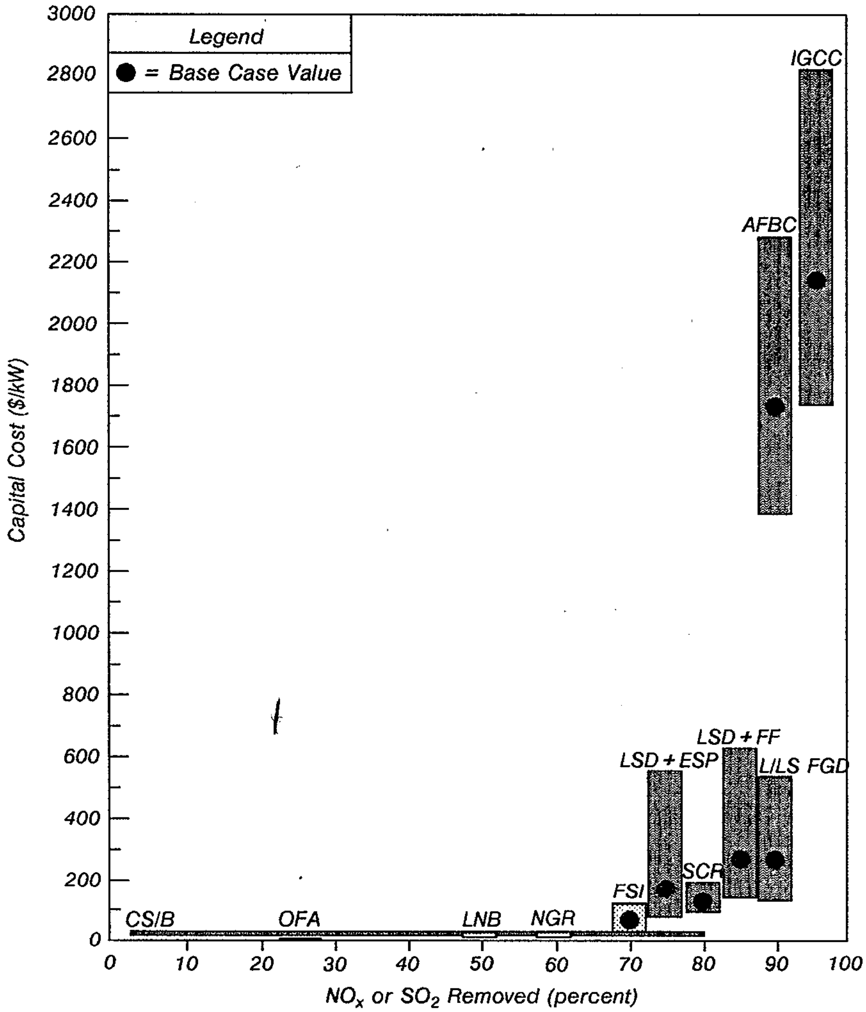

Figure 1. *Capital costs — constant 1988 dollars.*

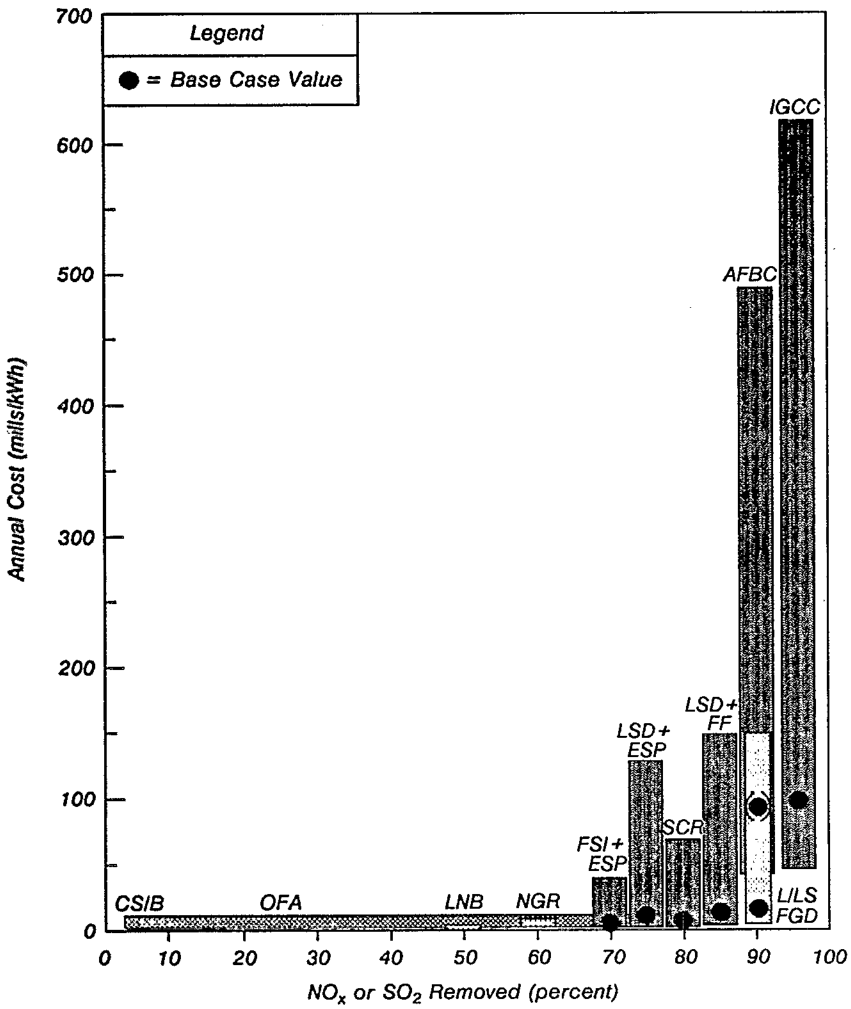

Figure 2. *Levelized annual cost — constant 1988 dollars.*

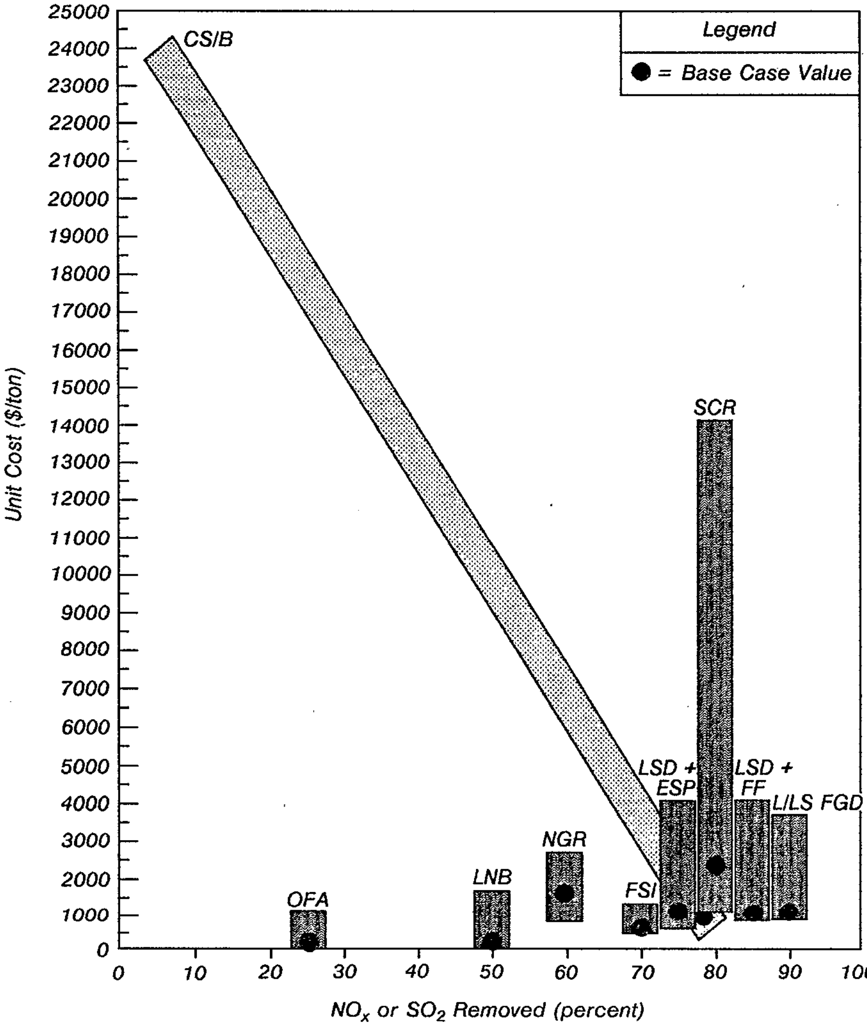

Figure 3. *Unit cost — constant 1988 dollars.*

D.M. White and M. Maibodi are with Radian Corp., Research Triangle Park, NC 27709.
***Norman Kaplan** is the EPA Project Officer (see below).*
The complete report, entitled "Assessment of Control Technologies for Reducing Emissions of SO_2 and NO_x from Existing Coal-fired Utility Boilers," (Order No. PB90-273574/AS; Cost: $31.00 subject to change) will be available only from:
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
Telephone: 703-487-4650
The EPA Project Officer can be contacted at:
Air and Energy Engineering Research Laboratory
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

United States
Environmental Protection
Agency

Center for Environmental Research
Information
Cincinnati, OH 45268

BULK RATE
POSTAGE & FEES PAID
EPA PERMIT NO. G-35

Official Business
Penalty for Private Use $300

EPA/600/S7-90/018