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Project Summary

Comparison of West German and U.S. Flue Gas Desulfurization and Selective Catalytic Reduction Costs

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By the end of the 1980s, more than 45,000 MWe and, by early 1990, more than 34,000 MWe of coal- and oil-fired utility boilers in the Federal Republic of Germany (FRG) will have been retrofitted with flue gas desulfurization (FGD) and selective catalytic reduction (SCR), respectively. This report documents a comparison of the actual cost of retrofitting FGD and SCR on FRG boilers to cost estimating procedures used in the U.S. to estimate the retrofit of these controls on U.S. boilers. The estimated capital costs of FGD using the U.S. procedures compared well to the reported capital cost for the 13 FRG boilers evaluated. The difference between the estimated and actual costs was -8 to 12%. However, there are significant design differences between U.S. FGD systems built to comply with New Source Performance Standards (NSPS) and the FRG systems. These differences, which result in significantly lower capital costs on a dollar per kilowatt basis for the FRG systems, include: no spare absorber modules, large scrubber modules, and smaller sorbent and waste handling systems due to the low sulfur coals burned in the FRG. The estimated capital cost of SCR using the U.S. procedures also compared well to the reported capital costs for the nine FRG boilers evaluated. The difference was between -5 to 16%. However, the U.S. procedures were modified to reflect the catalyst volume and cost used in the FRG boilers. The previous U.S. estimates used larger catalyst volumes and higher catalyst costs, and incorporated process contingences that were not used in this study to develop the SCR cost estimates.

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

In the mid-1980s, the Federal Republic of Germany (FRG) enacted legislation requiring significant reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from existing large utility boilers. As a result, by 1988 more than 45,000 MWe of conventional lime/limestone (L/LS) flue gas desulfurization (FGD) and lime spray drying (LSD) FGD systems had been installed, and by 1990 more than 34,000 MWe of selective catalytic reduction (SCR) systems will have been installed. The reported capital costs for the L/LS- and LSD-FGD systems appear to be much lower than the actual costs of similar systems in the U. S. The reported capital costs of the SCR systems are also much lower than the estimated cost of applying SCR systems to U.S. utility boilers.

This report documents the results of an analysis for comparing estimated versus actual capital costs for FGD and SCR systems installed at several utility boilers in the FRG.

Methodology

The effort was conducted in two phases. In Phase 1, site visits were conducted at five coal-fired utility boiler power plants in the FRG. Two of the plants (Walheim and Mannheim) were set up by the Institute for Industrial Production (IPP); two other plants (Niederaussem and Scholven) were visited as part of a North Atlantic Treaty Organization (NATO) committee meeting on the Control of Air Pollution from Coal Combustion, and the fifth plant (Ibbenbueren) visit was set up by EPA's contractor. Table 1 summarizes the boiler and coal characteristics for the five plants visited and evaluated under this study.

Prior to the site visits, a questionnaire was sent to each utility company with the information needs of the study. This questionnaire provided the basis for the data gathering effort conducted during the plant visits. This data collection effort focused on obtaining capital cost information, general design and operating parameters, plot plans, and aerial photographs of the FGD and SCR systems.

In Phase 2, the collected information was used to develop cost estimates based on U.S. cost estimating procedures. The procedures used were developed under a National Acid Precipitation Assessment Program (NAPAP) project that estimated the cost and performance of SO_2 and NO_x controls at existing coal-fired utility boilers. The FGD procedures were based on the Electric Power Research Institute (EPRI) report. The SCR cost estimating procedures were based on an EPRI report and a Tennessee Valley Authority (TVA) report funded by U.S. EPA. The capital cost estimates developed using the U.S. procedures were then compared to the reported costs for plants evaluated under this study. This comparison was conducted to identify capital cost differences, reasons for the differences, and changes needed to the cost estimating procedures.

Table 1. *German Plant Visits*

Plant/Units	*Fuel Type[a]*	*Size (MWe)*	*Boiler Type[b]*	*SCR Type[c]*	*SCR On-line Date*	*FGD Type[d]*	*FGDOn-line Date*
Walheim 1	*HC*	*103*	*WB*	–	–	*LSD*	*1987*
2	*HC*	*153*	*WB*	*HD*	*1988*	*LSD*	*1987*
Mannheim 3,4	*HC*	*2x220*	*WB*	*TG*	*1988*	*LS*	*1988*
7	*HC*	*475*	*DB*	*HD*	*1988*	*LS*	*1988*
Ibbenbueren B	*HC*	*770*	*WB*	*TG*	*1988*	*L*	*1987*
Niederaussem A-H	*LG*	*9x300*	*DB*	–	–	*LS*	*1988*
Scholven B	*BC*	*370*	*DB*	*HD*	*1989*	*LS*	*1988*
C	*BC*	*370*	*DB*	*HD*	*1989*	*LS*	*1988*
D	*BC*	*370*	*DB*	*HD*	*1989*	*LS*	*1987*
E	*BC*	*370*	*DB*	*HD*	*1989*	*LS*	*1987*
F	*HC*	*740*	*DB*	*HD*	*1989*	*LS*	*1979-87*
G,H	*Oil*	*2×714*	*Oil*	*HD*	*1986-87*	–	–

[a]Coal types: HC = hard coal, LG = lignite, BC = ballast coal.
[b]Boiler types: DB = dry bottom, WB = wet bottom.
[c]SCR types: HD = high dust, TG = tail gas.
[d]FGD types: LSD = lime spray drying, L = lime, LS = limestone.

Summary of FGD Results

Table 2 summarizes the capital cost comparison for L/LS- and LSD-FGD for four of the plants. Capital cost estimates were not available for the individual boilers at the Scholven plant. The estimated capital costs for L/LS-FGD versus the reported actual costs were very close, having an absolute difference between -8 and 12%. Likewise, the average difference for the two LSD-FGD systems was 12%. The conversion rate used for this analysis was 2 deutsche marks (DM) to the U.S. dollar. The following changes were made to the FGD cost estimating model for this study.

Number of Spare Absorber Modules

None of the FGD systems evaluated in the FRG have spare absorber modules because German legislation allows the plant to be out of compliance for 240 hours a year. Therefore, the boiler does not have to shut down due to FGD system operation problems. In the U. S., the 1979 New Source Performance Standard (NSPS) does not allow a boiler to operate out of compliance unless a spare absorber module is available. Additionally, operating out of compliance for any significant amount of time would result in noncompliance with the 30-day rolling average emission limit. As a result, most U.S. utility companies have chosen to have spare absorber modules rather than reduce the load or shut down when the FGD system is not operating adequately. This increases capital costs by 20% for a 500-MWe unit.

Scrubber Module Size

Many L/LS-FGD modules at the FRG plants handled 300-500 MWe equivalent of flue gas. Large module sizes reduce capital costs due to economy of scale. The size of most U.S. scrubber modules is typically 100-150 MWe to minimize spare module costs.

Sorbent and Waste Handling Quantities

All FRG coals are low in sulfur (~1%), which results in lower capital costs due to smaller sorbent and waste handling systems. By contrast, U.S. boilers have coal sulfur contents of 1 to 4%. Additionally, most of the L/LS-FGD systems in FRG receive the sorbent pulverized, and the capital cost for pulverization is reflected in the cost of the sorbent (consumables) and not in the system capital costs.

General System Design

The FRG FGD systems represent current FGD design concepts, which in general are less complex and lower in capital costs than those built in the U.S. before 1985. Process design simplification examples include single-loop scrubber with slurry addition and oxidation in the scrubber bottom, and the use of hydroclones instead of thickeners before vacuum belt dewatering. These designs represent state-of-the-art technology and are used on new U.S. systems.

Combined Systems

Another factor which affects the capital cost of FGD systems is the system size. Larger systems cost less on a $/kW basis because of economies of scale. Because the FRG regulations required almost all utility boilers to retrofit scrubbers, flue gas from adjacent boilers at the same plant were typically tied into a single large FGD system. Thus, economies of scale resulted from having a single large system, instead of multiple smaller ones, and from having larger absorber modules. For example, at the Niederaussem plant a 2700 MW system was constructed instead of eight units ranging in size from 150 to 600 MW.

Summary of SCR Results

Table 3 summarizes the capital cost comparison for SCR at four of the plants. Capital cost estimates were not possible at the lignite-fired plant in Niederaussem because these boilers are expected to meet the NO_x emission limit by retrofitting combustion modification controls. As Table 3 shows, the difference between the actual cost and the estimated capital cost varied between -5 and 16%. Catalyst volume and costs for the SCR systems were based on information from the plants. Access and congestion retrofit difficulty and scope adders were estimated based on procedures developed for FGD systems. The study results confirm that the major variables that affect the capital cost are catalyst volume and cost, retrofit difficulty, and scope adder costs. However, still unknown is the expected catalyst life when firing U.S. coals having high sulfur, alkali metal and/or arsenic contents.

Access and congestion retrofit difficulty and general facilities were estimated using the methodology developed for FGD systems. The following access and congestion retrofit factor description was found to give close approximation to the actual reported SCR capital costs:

- Base - Similar to new plant where there is free access for large cranes and equipment near the boiler (hot side) or chimney (cold side). The Ibbenbueren plant with a cold side SCR system behind the existing chimney is representative of this situation.
- Low - Space is somewhat limited such that a standard equipment layout is not possible, but access exists for large cranes on two sides. The Scholven units B-E with the hot side SCR reactors at ground level next to the ESPs are representative of this situation. Limited space existed between the units for locating the SCR reactors and cranes.
- Moderate - Limited space requiring special equipment designs and layouts and crane access limited to one side. The Scholven F and Mannheim 7 units represent this situation where the SCR reactors are elevated between the economizer and air heater, but outside of the boiler building. Both units are end units allowing for reasonable crane access.
- High - Severe space limitations with access for large cranes blocked on all sides. The Walheim 2 unit represents this situation where the boiler building wall was removed to allow access to construct the SCR reactors between the economizer and air heater.

Table 2. *Summary of FGD Capital Cost Comparison*

Plant Name	*Mannheim*	*Ibbenbueren*	*Niederaussem*	*Walheim*
Boiler/Block	*7*	*B*	*A-H*	*1-2*
Coal sulfur	*1.0*	*1.0*	*1.0*	*1.0*
FGD type	*LS-FGD*	*L-FGD*	*LS-FGD*	*LSD-FGD*
FGD size (MWe)	*475*	*770*	*2700*	*256*
SO_2 removal efficiency (%)	*80*	*85*	*90*	*90*
Number of absorbers	*1*	*2*	*9*	*2*
Estimate of retrofit difficulty	*1.10*	*1.10*	*1.87*	*1.16*
Access/Congestion factor	*Low*	*Low*	*Low*	*Low*
Scope adder costs ($/kWe)	*0*	*0*	*4.6*	*0*
General facilities (%)	*8*	*5*	*5*	*10*
Total capital cost ($/kWe)				
EPA Contractor's Estimate	*140*	*119*	*260*	*190*
Actual reported[a]	*140*	*130*	*240*	*170*
Percent difference	*0*	*-8*	*8*	*12*

[a]Costs are based on an exchange rate of DM 2 to the U.S. dollar.

Conclusions

Flue Gas Desulfurization

The results of this study show that FRG capital costs for conventional lime/limestone wet and dry FGD systems are similar when differences in the scope of supply (design) are taken into account. The major design differences between the FRG and U.S. designed systems are due to:

- Coal Sulfur Content - Higher coal sulfur content of most U.S. coals results in higher capital costs for sorbent and waste handling facilities and use of spare absorbers to ensure operating reliability.
- Combined Systems - Most FRG systems are large because of flue gas from multiple units is processed in one system. Combined systems have lower capital cost requirements due to economy of scale.
- Regulatory - NSPS bypass and averaging provisions have resulted in use of spare modules and small absorber sizes to minimize cost of spare absorbers.
- Technology Status - Most FRG systems employ 1980s technology whereas most U.S. systems employ 1970s technology because of when the systems were built. Newer designs are more reliable, reduce the need for spare absorbers, and allow the use of larger absorber sizes.

Results of this study indicate that:

1. The lower capital cost of FGD systems in FRG relative to U.S. systems is due to scope of the supply (design) differences.
2. Future U.S. systems will have lower capital cost requirements than past systems due to technology improvements.
3. Regulatory provisions having less stringent bypass and averaging requirements than NSPS can significantly reduce the capital cost of FGD systems.
4. Combined handling of flue gas from multiple units can significantly reduce system capital costs.

Selective Catalytic Reduction

Study results show that FRG SCR system capital cost can be accurately estimated if catalyst cost and retrofit difficulty are known. The retrofit difficulty adjustment methodology found in an EPRI report can be used to account for different access and congestion situations in the FRG. Study results indicate that:

1. The FRG SCR system capital costs can be used to estimate U.S. retrofit applications if adjustments for retrofit difficulty and catalyst costs are made.

2. Because of the differences in U.S. coal trace element content versus that of FRG, the catalyst life requirements of the FRG applications are not directly transferable to all U.S. applications. As such, catalyst life assumptions used to estimate annual costs must reflect this uncertainty.

The following contaminants found in utility boiler flue gases over time deactivate the catalyst: SO_x, particulate matter, arsenic, and alkali metals. The contaminants vary with the fuel and reactor location. SCR has been commercially applied in Japan and Germany to the following utility boiler situations:

Fuel Characteristics			SCR Configuration	
Fuel Type	Ash Metals	Sulfur Level	Temperature	Dust
Gas	None	None	Hot	None
Oil	Low	Low	Hot	Low
Coal	Low	1 Percent	Hot/Cold	Low/High
Coal	High Arsenic	1 Percent	Hot/Cold	Low/High

SCR has not been applied commercially with high sulfur and high alkaline coals. Many boilers in the U.S. burn high sulfur coals (2-5%) and coals with highly alkaline ash (lignites and subbituminous coals). Also, many of the low sulfur eastern coals have high arsenic contents. To address the lack of data available on catalyst life for hot side SCR for U.S. coals, a number of SCR pilot programs are planned.

Table 3. *Summary of SCR Capital Cost Comparison*

Plant Name	Mannheim	Ibbenbueren	Walheim	Scholven	Scholven
Boiler/Block	7	8	2	B-E	F
Boiler type	Dry bottom	Wet bottom	Wet bottom	Dry bottom	Dry bottom
SCR type	Hot	Cold	Hot	Hot	Hot
SCR size (MWe)	475	770	153	370 each	740
NO_x removal efficiency (%)	77-82	91-92	88	67	60
Access/Congestion factor	Moderate	Base	High	Low	Moderate
Scope adder cost ($/kWe)	3.0	47.7	42.5	3.1	3.4
General facilities (%)	13	25	13	13	13
Catalyst cost					
Dollars/ft³[a]	504	355	545	283	283
Dollars/kWe	18.7	7.4	25.2	16.2	7.8
Total capital cost ($/kWe)					
Radian estimate	82	98	180	87	57
Actual reported[b]	79	103	189[c]	75	55
Percent difference	4	-5	-5	16	3

[a] $1\ m^3 = 35.3\ ft^3$.
[b] Costs are based on an exchange rate of DM 2 to the U.S. dollar.
[c] Excludes the costs of combustion modifications.

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The complete report, entitled "Comparison of West German and U.S. Flue Gas Desulfurization and Selective Catalytic Reduction Costs," (Order No. PB 90-206 319/AS; Cost: $17.00, subject to change) will be available only from:
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