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Project Summary

Analysis of Utility Control Strategies Using the LIMB Technology

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The report gives results of a study to evaluate the impact of proposed acid rain legislation on the potential application of limestone injection multistage burner (LIMB) technology to achieve sulfur dioxide (SO_2) and nitrogen oxide (NO_x) reductions at coal-fired utility power plants.

The study found that proposed acid rain legislation, which mandates the retrofit of high efficiency control technologies such as flue gas desulfurization (FGD) or which requires national SO_2/NO_x reduction levels greater than 10 million tons per year, would significantly reduce the application of LIMB. For regulatory strategies which do not mandate the use of FGD and which require emission reductions of 8 to 10 million tons per year, the potential LIMB application ranges from 15,000 to 100,000 MW of coal-fired boiler capacity in the 31 eastern state acid rain region.

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

A number of bills have been proposed by Congress that would require reductions of acid rain precursor emissions. These congressional bills would require different mixes of emission control technologies to achieve SO_2 and NO_x reductions at coal-fired utility power plants. The objective of this research program was to evaluate the impact of proposed acid rain legislation on the potential application of LIMB technology incorporating recent LIMB research and development findings.

A number of regulatory strategies and emission reduction targets were developed by reviewing acid rain legislation proposed in the 97th and 98th congressional sessions. For each regulatory strategy developed, the control technology mix of LIMB, FGD, and coal switching required to achieve the selected emission reduction level was determined. Next, the maximum number of boilers to which LIMB technology could be applied was determined by examining technical and regulatory constraints and emission reduction targets. The cost effectiveness of each regulatory case and control technology mix was estimated to evaluate the cost of each control technology mix.

Regulatory Case Development

The primary differences in the congressional bills are a result of the level of SO_2 reductions that is required at each plant due to plant/boiler specific emission limits or due to requiring high overall SO_2 reduction levels. All of the bills use 1980 as the base year for which emission reduction levels apply. Differences in the method of calculating excess emissions, implementation years, financing methods, and state reduction allocation and implementation were not considered important for the purposes of this study. The following three legislative/regulatory cases were analyzed:

Regulatory Case	SO_2 Reductions, million tons/yr
Boiler Performance Standard	10
Regional Reduction Levels	10
Regional Reduction Levels	8

For this study, a regulatory strategy was developed based on bills which base reductions on boiler and/or state reduction performance standards (S 1709, HR 4816, HR 3400). These bills require that existing boilers must comply with New Source Performance Standards (1971 or 1979) if their emissions are greater than a specified amount of SO_2 per million Btu of fuel. These bills also require state wide reductions. Because these bills require very high levels of SO_2 reduction at individual plants/boilers, the use of wet FGD will be required at most affected plants. These legislative cases are entitled "Boiler Performance" cases, and FGD is applied to boilers at the largest emitting utility power plants.

The other major type of bill introduced in Congress (HR 4829, S 3041) allocates state level emission reductions generally based on the portion of emissions from facilities with emission rates greater than 1.2 lb SO_2 per million Btu fuel input. These bills allow the states to determine how the allocated emission reductions for that state are to be achieved and in some cases allow trading of emission reductions. Because these bills provide much greater flexibility in how emission reductions are achieved on a plant/boiler basis, they do not require the use of certain types of SO_2/NO_x control technologies. Study cases based on this type of legislative scenario are entitled "Regional Reduction" cases.

The other major difference between bills that would impact the mix of control technologies used by utilities is the amount of emission reduction required because, as the SO_2 reduction target increases, the average emission reduction needed to be achieved at each coal-fired boiler increases. For this study three SO_2 emission reduction levels were evaluated: 8 and 10 million tons per year, consistent with the different levels proposed by the congressional bills reviewed; and 12 million tons per year, a sensitivity case to evaluate the impact that this level of reduction would have on the control technology mix needed to achieve this high level of reduction.

The Congressional bills differ in the amount of credit given for NO_x reductions. For this study half credit was given for NO_x reductions; e.g., 1.0 ton of NO_x removed equals 0.5 ton of SO_2 reduction. Thus, for this study, a NO_x credit was included for low NO_x combustion modification assumed to be made with furnace sorbent injection.

Region and Boiler Specific Data Base

A major part of the study was development of a boiler specific data base and boiler specific control costs for LIMB, FGD, and coal switching. Developing an accurate data base for all coal-fired boilers in the 31 eastern states was not feasible. However, an accurate data base was easily developed for the top 100 SO_2 emitting coal-fired utility power plants. These top 100 plants accounted for over 72% of total U.S. utility power plant SO_2 emissions in 1980. Results of the applicability study for the top 100 plants were then extrapolated to the boilers in the 31 eastern state region. SO_2 emission reduction targets used for each regulatory case, based on allocating 72% of the emission reduction target to the top 100 coal-fired boiler population, are

Regulatory Strategy	SO_2 Emission Reduction From Top 100 Plants, 10^6 tons per year	Total Required SO_2 Reduction, 10^6 tons per year
Boiler Performance Standard	7.2	10
Regional Reduction	7.2	10
Regional Reduction	5.8	8
Regional Reduction	8.6	12

Control Technology Performance/Cost

Three coal-fired boiler SO_2 reduction technologies were examined: (1) limestone FGD with 90% SO_2 control; (2) LIMB with 50-60% SO_2 control and 50% NO_x control; and (3) switching to 2.5 lb SO_2 per million Btu eastern bituminous coal.

Boiler specific costs for FGD and LIMB were provided, using the IAPCS-2 computer model. Table 1 summarizes the cost/performance assumptions used to make the computer runs.

The cost of coal switching was based on a coal cost differential of $1.00 per million Btu above the current higher sulfur coal. Although boiler specific costs for high and low sulfur coals were available, due to the current soft market, several plants are actually obtaining low sulfur coal at prices below high sulfur coal. This is not anticipated if many plants were required to switch coals because the added demand for low sulfur coal would drive up its price relative to high sulfur coals.

Discussion of Results

Figures 1 and 2 summarize the results of the 10 million ton per year SO_2 reduction cases. Figures 3 and 4 summarize the results of the 8, 10, and 12 million ton per year SO_2 reduction cases.

10 Million Ton Per Year SO_2 Reduction Cases

Figure 1 summarizes the results of the 10 million ton per year SO_2 reduction cases. Two cases were run for the Boiler Performance Standard strategy to provide an upper and lower bound on the amount of LIMB which would be used to achieve the desired SO_2 reductions. In both cases, FGD was applied to the boilers in the top 50 SO_2 emitting power plants with post 1965 service year achieving over 5.5 million tons per year of SO_2 reduction. In the first case LIMB was applied to the remaining boilers which were considered technically applicable (post 1960 wall/tangential fired boilers with sulfur emissions between 1.2 and 6.0 lb/million Btu). This case results in 69,000 MW of FGD application, 13,000 MW of LIMB application and 3,000 MW of coal switching. For the second Boiler Performance Standard case, coal switching (MAX CS) was applied before LIMB resulting in 8,400 MW of coal switching. Because coal switching can be achieved on the 1950's boiler to meet the required emission reduction target, no LIMB was applied.

Three different cases were run for the 10 million ton per year regional allocation scenario. The first two cases provided an upper and lower bound on the amount of LIMB which would be used versus coal switching. The other case looks at the impact of high performance (HP) LIMB (60% SO_2 reduction). For the maximum (MAX) LIMB case, LIMB was applied first to the applicable boilers resulting in half of the boiler population (71,000 MW) being controlled with the LIMB technology, 15,000 MW of FGD, and 11,000 MW of coal switching. For the second 10 million ton reduction case, coal switching was maximized (MAX CS) by applying it first to all the 1950's boilers. This reduces LIMB application to 65,000 MW and increases

Table 1. *Performance and Cost Parameters Used to Estimate FGD and LIMB Annualized Costs and Emission Reductions*

LIMB Performance Parameters

50% LIMB Cases	*60% LIMB Cases*
50% SO_2 Reduction	*60% SO_2 Reduction*
50% NO_x Reduction	*50% NO_x Reduction*
Calcitic Hydrate	*Calcitic Hydrate*
2.5:1 Ca/S Ratio	*3:1 Ca/S Ratio*
700°F Quench Rate	*700°F Quench Rate*

ESP upgrade and SO_3 conditioning for control of additional particulate matter.

FGD Performance Parameters
90% SO_2 Reduction and No NO_x Reduction
Limestone Slurry Sorbent
No Spare Absorbers
Number of Absorber Towers Based on Boiler Size:

Boiler Size, MW	*No. of Towers*
<100	*1*
100-250	*2*
250-500	*3*
500-750	*4*
>750	*5*

General Cost Bases
EPRI Cost Premises Used
Costs are in 1995 Dollars
Equipment Book Life of 15 Years
FGD Retrofit Difficulty Factor: 1.2 Times New Plant Cost

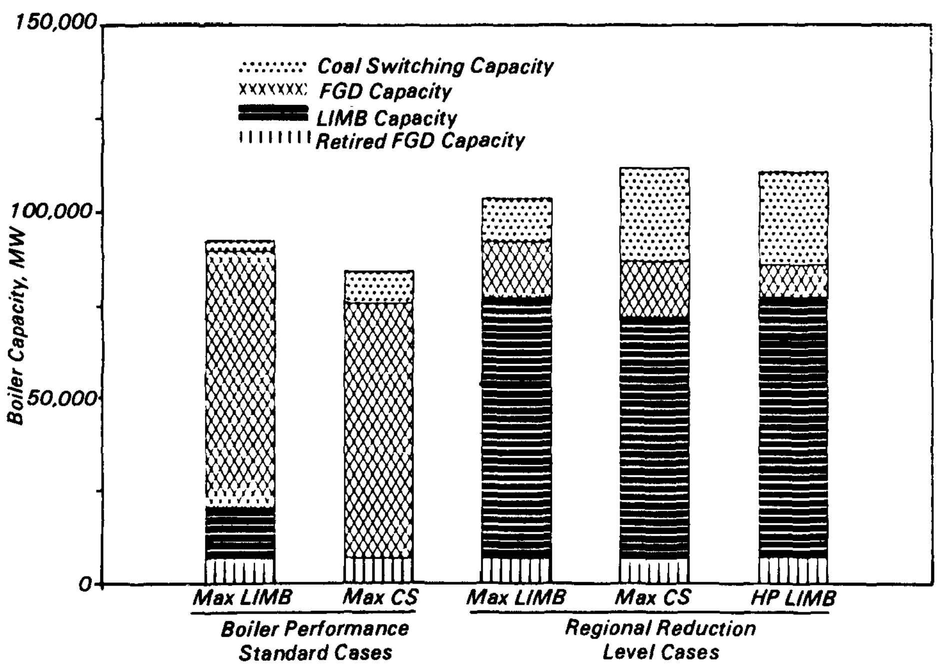

Figure 1. *Boiler application results for 10 million ton per year of SO_2 reductions.*

coal switching to 25,000 MW of application. For the third 10 million ton per year reduction case, high performance (HP LIMB) LIMB was applied, followed by FGD and coal switching as in the MAX LIMB case. This case decreases the penetration of FDG due to the greater SO_2 reduction achieved by high performance (60%) LIMB technology.

Figure 2 summarizes the cost results in the five 10 million ton per year SO_2 reduction cases. The boiler performance standard cases have the highest annual control cost of $13-$14 billion per year due to the large number of boilers which must apply FGD. The regional annual costs of the regional reduction level cases are significantly lower and range from $9.9 to $11.7 billion per year.

8, 10, and 12 Million Ton Per Year Cases

Figure 3 presents the results analyzing the impact of various emission reduction scenarios on the application of LIMB. The 10 million ton per year SO_2 reduction case is the same as for the Max LIMB regional allocation case discussed above. For this case, 71,000 MW of LIMB was applied to achieve the emission reduction target.

For the 8 million ton per year reduction case, coal switching to the 1950's boilers was applied first (lowest unit cost), followed by LIMB and FGD to achieve the emission reduction target. This results in boiler application of 71,000 MW of LIMB, 25,000 MW of coal switching, and 3,200 MW of FGD.

For the 12 million ton per year emission reduction case, the application of LIMB cannot be maximized if the emission reduction target is to be achieved. For this case, LIMB application was reduced by increasing the use of FGD and allowing all boilers where FGD and LIMB were not applied to switch coal. This results in the following boiler applications: 38,000 MW of LIMB, 50,000 MW of FGD, and 25,000 MW of coal switching.

Figure 4 presents the annual cost for the three cases. The annual costs and unit costs increase significantly as the emission reduction levels increase over 10 million tons per year:

Annual Reduction, 10^6 tons per year	Increase Emission Reduction, %	Increase in Cost, %	Average Unit Cost, $/ton
8	—	—	1381
10	25	23	1397
12	50	73	1678

These cost increases are due to the significantly increased application of FGD needed to obtain the very high overall average emission reductions per boiler/plant.

31 Eastern State Region

To estimate the potential LIMB applicability for all of the coal-fired boilers in the 31 eastern state region, the number of boilers in that region that fit the LIMB and FGD technical applicability was determined from the 31 eastern state utility boiler data base. The amount of capacity for which LIMB was applicable was 103,000 MW. The amount of FGD capacity for this boiler population was 108,000 MW.

The average unit cost of applying FGD to the applicable boilers not in the top 100 plants is significantly greater due to the smaller boiler sizes and lower coal sulfur contents. This means that LIMB technology would be favored over FGD, and the LIMB applicability potential for the 10 million ton per year SO_2 reduction strategy not mandating the use of FGD could be as high as 100,000 MW of boiler capacity.

Conclusions

This study indicates that up to 100,000 MW of boiler capacity of LIMB application is possible depending on the type of acid rain legislation adopted and the amount of coal switching that is economically and politically practical. Currently proposed legislative strategies requiring SO_2 reductions of 8-10 million tons per year will maximize the application of LIMB because it is anticipated to be more cost effective than FGD. Control strategies requiring SO_2 reductions greater than 10 million tons per year will decrease the application of LIMB, because the average level of SO_2 control required at each boiler would exceed that available with a broad application of LIMB. Legislative strategies which would require high levels of control (>60%) at each boiler would also reduce the application of LIMB unless combined with fuel substitution.

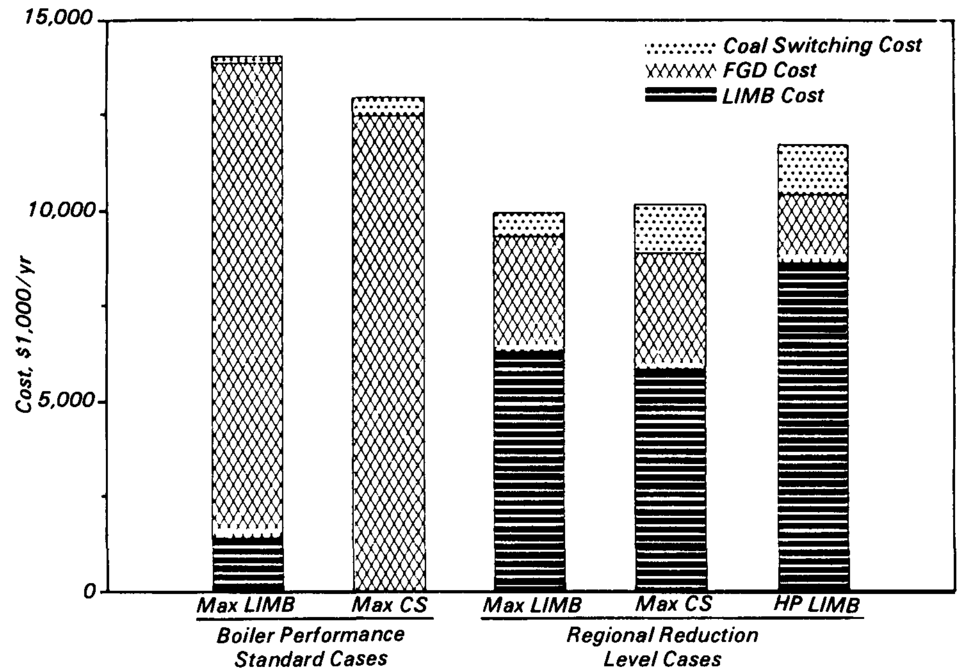

Figure 2. *Levelized annual cost of control (1995 $).*

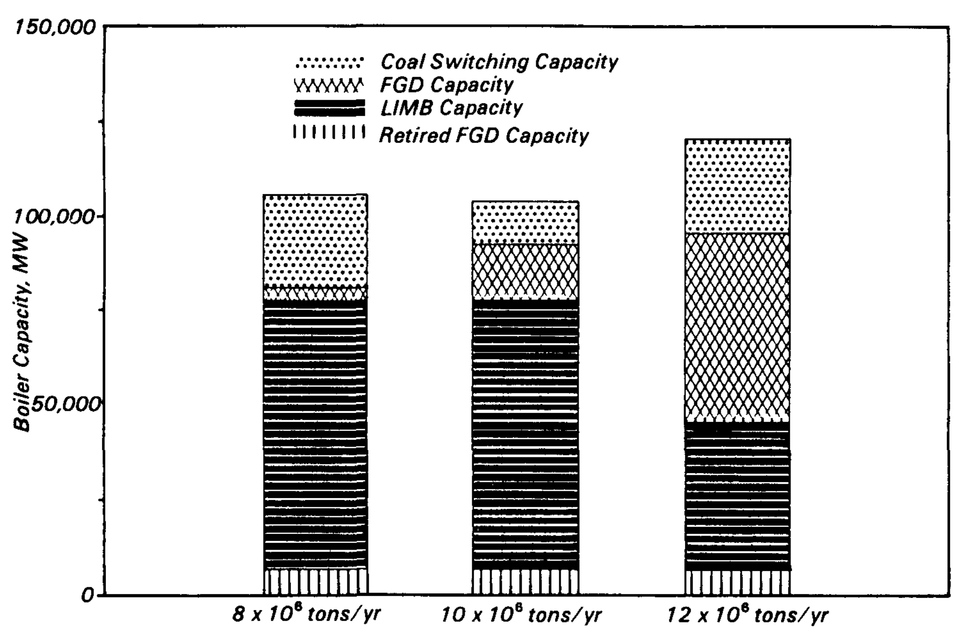

Figure 3. *Boiler application results for 8, 10, and 12 million ton per year cases.*

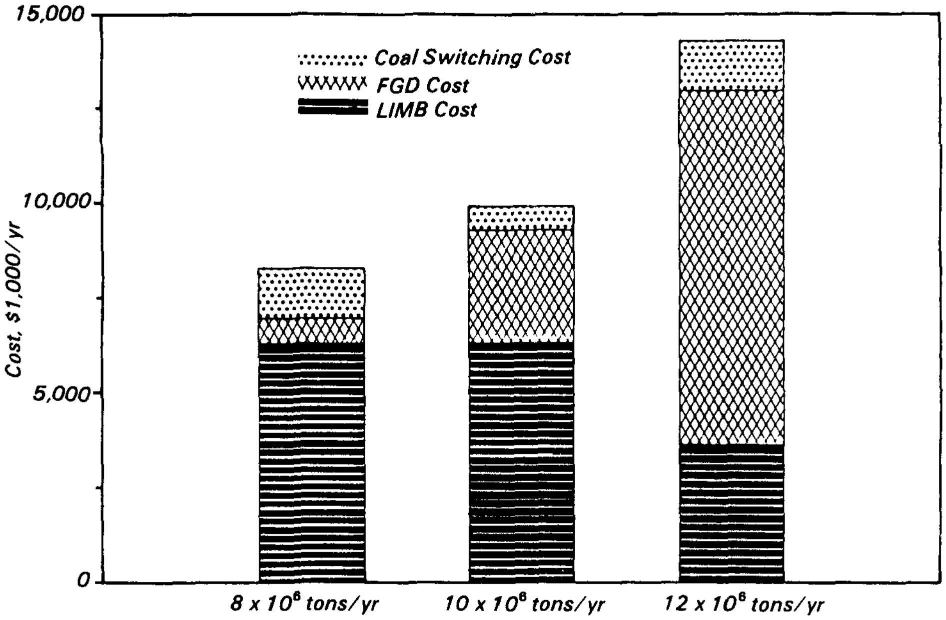

Figure 4. *Levelized annual cost of control for 8, 10, and 12 million ton per year cases (1995 $).*

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***Norman Kaplan** is the EPA Project Officer (see below).*
The complete report, entitled "Analysis of Utility Control Strategies Using the LIMB Technology," (Order No. PB 87-100 574/AS; Cost: $9.95, subject to change) will be available only from:
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Telephone: 703-487-4650
The EPA Project Officer can be contacted at:
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- Indirect heated —Unisulf on Unishale B gases
- Integral combustor —DEA + Stretford on Lurgi gases
  —Unisulf on Unishale C gases

Major equipment costs were taken from EPA Pollution Control Technical Manuals (PCTMs). ASSP equipment was sized and costs factored from inhouse data and PCTMs. Costs were factored to first quarter 1985.

Results of the cost study showed changes in incremental capital and operating costs for ASSP relative to conventional processing (see Table 1).

These cost comparisons show that the best potential for application of ASSP are processes that already have a spent shale combustor integrated into the retorting process (e.g., Lurgi, Unishale C, Chevron STB, and Tosco HSP). Capital and operating cost savings for Unishale C and Lurgi are primarily a result of deleting the Unisulf and Stretford plants.

Economics for the indirect and direct heated retorts are good to marginal. Factors which will affect the economics are:

- How effectively combustor heat can be utilized (simple steam raising is the least desirable).
- The value of steam.
- The use of fast or circulating fluid beds to reduce investment in combustor equipment.

Phase II Pilot Plant Testing

Pilot plant tests were performed in a bubbling fluid bed combustor of the type which is integrated into the retort process. A total of 44 individual tests were performed. Variables evaluated were combustor temperature, solids residence time, gas residence time, oxygen concentration, inlet gas sulfur concentration, staged combustion, and raw shale injection. Over the entire range of conditions tested, emissions of primary pollutants were:

Component	Range
SO_2	1-38 ppmv
NO_x	80-670 ppmv
CO	0.05-1.80 vol %
Trace Hydrocarbon	51-8465 ppmv

Key findings of the tests were:

- SO_2 emissions were easily controlled to low levels at virtually all conditions tested, probably as a result of the high Ca/S ratios used.
- NO_x emissions were primarily sensitive to oxygen concentration, as were SO_2 emissions to a lesser extent (Figure 2). Reasonably good NO_x control could be obtained with flue gas oxygen concentrations below about 3 vol %. The lowest NO_x concentrations were seen at O_2 levels approaching zero but at the expense of higher CO and trace hydrocarbon emissions.
- CO and trace hydrocarbon emissions were primarily sensitive to flue gas oxygen concentration (Figure 3). Good control of both could be obtained at O_2 levels above about 2 vol %.

Emissions of NO_x move in a direction opposite to SO_2, CO, and trace hydrocarbon emissions. Thus, operating conditions that minimize all four represent a compromise. One test was run which produced nearly optimum results.

Conditions for this test were:

Bed Temperature	664°C
Solids Residence Time	9.4 min
Gas Residence Time	0.9 sec
Gas Supply Velocity	134.1 cm/sec
Flue Gas O_2	2.6 vol %
Ca/S Mole Ratio	10.3
Raw Shale/Spent Shale Ratio	1:36

At these conditions the following results were obtained:

SO_2	11 ppmv
NO_x	160 ppmv
CO	0.27 vol %
Trace Hydrocarbon	388 ppmv
Combustion Efficiency	89 %

During selected tests, both combustor flue gas and retort gas were sampled and analyzed for selected trace elements: mercury, cadmium, arsenic, lead, beryllium, and fluorine. During these tests, solids streams were also analyzed for trace elements in an attempt to determine where trace elements go. One run was performed where a spike solution of mercury and cadmium was added to the combustor.

Results of the trace element tests indicated some relative trends with regard to emissions but, because of the brevity of the sampling, no hard conclusions can be reached which would allow extrapolation of results to long-term steady-state operations. Some of the key observations were:

- Lead, beryllium and fluorine were found to have low volatility; i.e., of the amounts present in raw shale, only very small percentages were volatilized to the gas streams.
- Arsenic was found in significant concentrations in the retort gas (100-400 ppmv), although the amount of arsenic found represented less than 15% of that in the raw shale.
- So little mercury was present in the raw shale that mercury emissions could not be characterized with high accuracy. Mercury emissions were very low except during the spike indicating that mercury, if present in higher concentrations in the raw shale, could possibly pose emissions problems.
- Although significant amounts of cadmium was found in the gases at higher retort and combustor temperatures, emissions represented less than 10% of cadmium present in raw shale.

There is some evidence that mercury and cadmium introduced to the combustor during the spike test condensed within the retort equipment and revolatilized over time. However, because of the limited number of samples taken, it would not be prudent to draw any conclusions. Longer term steady-state operations would have to be studied to determine the fate of mercury and cadmium with more certainty.

Table 1. *Cost Comparison For ASSP*

Retort Type	*Direct Heated Case A*	*Case B*	*Indirect Heated*	*Integral Combustor*	
Retorting Process	*MIS/Unishale C*		*Unishale B*	*Lurgi*	*Unishale C*
ASSP Incremental Cap. Cost, $\$10^6$	*−71.2*	*−63.2*	*+90.2*	*−13.0*	*−32.1*
ASSP Incremental Annual Oper. Cost, $\$10^6$/yr	*+10.83*	*+12.07*	*−19.21*	*−2.29*	*−1.56*

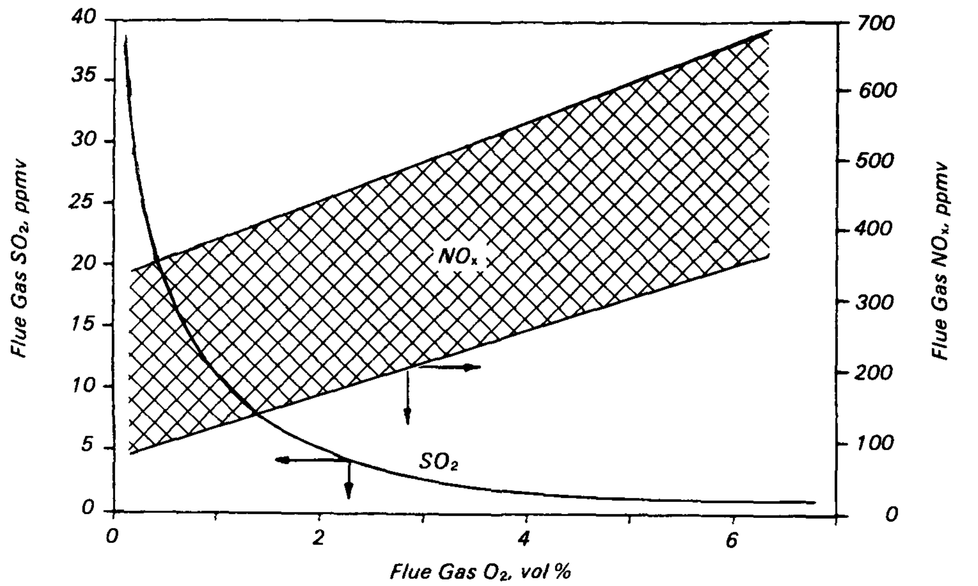

Figure 2. *Effect of flue gas oxygen on SO_2 and NO_x emissions.*

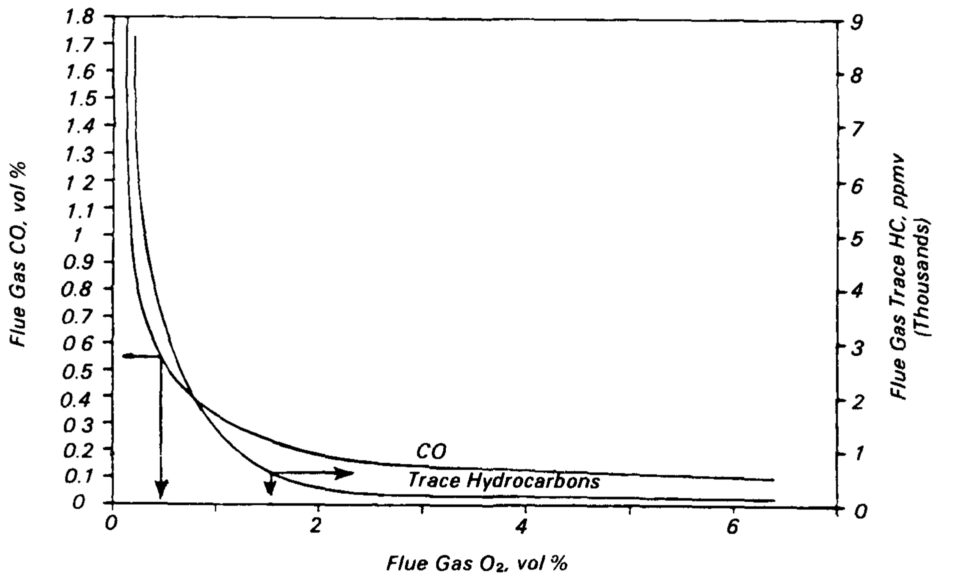

Figure 3. *Effect of flue gas oxygen on CO and trace hydrocarbon emissions.*

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