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# ALTERNATIVE $SO_2$ AND $NO_X$ EMISSION REDUCTION TECHNOLOGIES FOR STATIONARY SOURCES: A COMPARATIVE ANALYSIS*

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## 1.0 INTRODUCTION

Emission control of acid rain precursors is currently the subject of intense debate on Capitol Hill. Numerous bills have been introduced which call for substantial reductions in sulfur dioxide ($SO_2$) and nitrogen oxide ($NO_x$) emissions from operating utility and industrial boilers. The primary focus of the debates is on the cost, applicability and potential market impacts of emissions control options available to achieve the desired reductions. These topics are also the focus of a report in preparation for the 1990 Assessment of the National Acid Precipitation Assessment Program (NAPAP): *Technologies and Other Measures for Controlling Emissions: Cost, Performance and Applicability* (South, et al. 1990).

This paper summarizes some of the abatement technology information for utility boilers contained in the NAPAP report. First the major provisions in the proposed acid rain legislation are summarized (1.1) and the emission reduction options potentially applicable to the utility boiler population discussed (1.2). This is followed by a discussion of the retrofit issues for utility boilers (2.0) and a synopsis of the applicability and cost of retrofit emission control options (3.0). Since the focus of the current proposed legislation is on near-term reduction requirements for utility boilers, this paper emphasizes retrofit control options. See South, et al (1990) for a more complete discussion of repowering and retrofit control options and the application of these abatement techniques to industrial boilers.

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## 1.1 Major Provisions of Proposed Acid Rain Legislation

There are two major acid rain bills currently being examined in Congress: the final Bush Administration Clean Air Bill (S 1490, HR 3030) and S 1630 introduced by Senators Baucus, Chafee, et al. More recently, there is a ADministration/Senate compromise bill that contains a mixture of provisions in S 1490 and S 1630, with a variety of new concepts to address problems perceived by many regarding the equity of the allowance systems originally proposed in both bills. The result is a bill more complex than either of its predecessors, especially with respect to the allowance system. Since the provisions of the proposed legislation are still evolving, summarized below are only the principal elements of S 1630:

**Reduction Requirements**

- The bill requires a 10 million ton reduction in sulfur dioxide emissions below 1980 levels by the year 2000.
- National utility sulfur dioxide emissions are then capped at their year 2000 levels.
- New plants that cannot secure the needed offsets will be able to purchase them from a special EPA reserve.
- In Phase I, all utility power plants emitting at a rate above 2.5 pounds of sulfur dioxide per million Btu will have to reduce emissions to a level equal to 2.5 lbs/mmBtu multiplied by their average 1985-1987 fuel consumption measured in Btu. This category includes the largest 107 utility emitters, in 18 Eastern states. The reductions must be achieved by January 1, 1995.
- In Phase II, all utility power plants emitting at a rate above 1.2 lbs/mmBtu will have to reduce emission to a level equal to 1.2 lbs/mmBtu multiplied by their average 1985-1987 fuel consumption measured in Btu. These reductions must be achieved by January 1, 2000.
- 27 million tons of oxides of nitrogen reduced by the year 2000 (new ozone smog provisions in the bill will achieve additional $NO_x$ reductions).
- States that have invested in pollution control technology have no interim reduction requirement in recognition of this investment. This includes states where the statewide 1985 utility $SO_2$ emissions total is less than 150,000 tons and 50% of electricity production is from sources employing emissions control technology.

- Nationwide, plants that emit $SO_2$ at a low rate will be able to increase their emissions between now and the year 2000 by roughly 20% and will then be limited to that level in order to maintain the nationwide cap at the 10-million-ton reduction level.

- The 1977 percentage reduction requirement is repealed once the emissions cap goes into effect. EPA is directed to revise the emissions performance standard for new sources without a percentage reduction requirement.

**Marketable Allowances**

- In addition to its pollution control permit, each source will receive allowances equal to the tons of pollution it is permitted to emit.

- If a source reduces its pollution more than required, it will have left-over allowance it can sell to another source -- which would permit the second source to emit more than required while remaining in compliance.

## 1.2 Emission Reduction Options for Current Boiler Population

While many technological options exist to control $SO_2$ and $NO_x$ emissions from utility boilers, the potential for continued reduction of these pollutants from fossil fuel-fired boilers is a function of the boiler characteristics. Key characteristics include alternate fuel capability, age, furnace design, and the nature of the existing control equipment.

The majority of fossil fuel-fired utility boilers use coal as the primary fuel. The use of alternative fuels, oil or gas, would result in reduced $SO_2$ emissions and, generally, reduced $NO_x$ emissions. Not all boilers, however, can readily switch to alternate fuels. Figure 1-1 displays both the number of boilers and capacity of boilers with various fuel capabilities.

Overall, 67% of total boiler capacity is primarily coal-fired. Fully 42% of boiler capacity reports oil capability and 29% reports gas capability. This analysis has not established the overlap in these categories, so the total gas and oil capability is not indicated. Still, these results suggest a substantial fuel switching capability. It is important to note in this context that 96% of utility $SO_2$ and 91% of utility $NO_x$ emissions are from coal-fired plants.

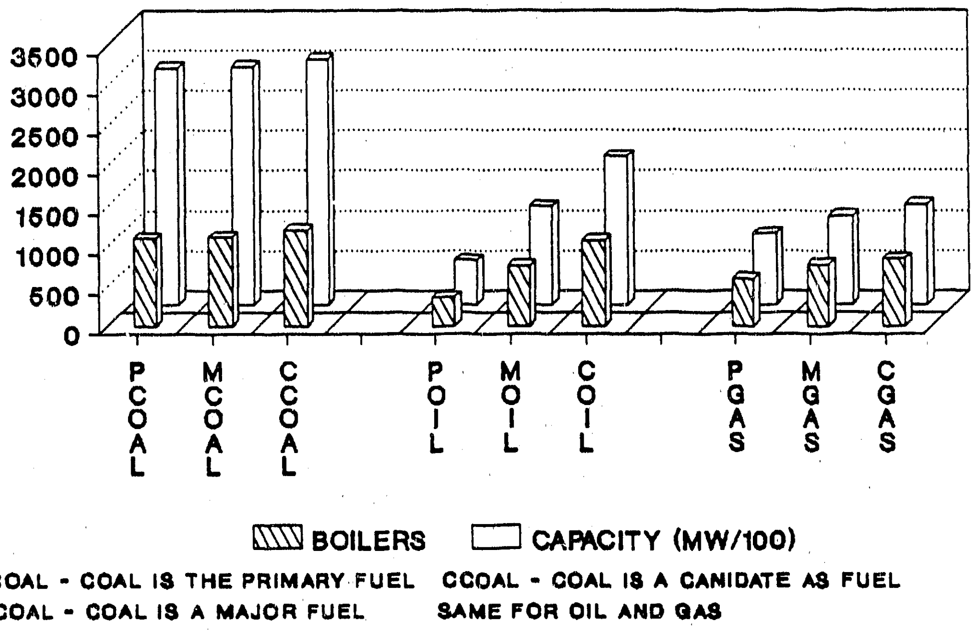


**Figure 1-1 Number of Boilers and Boiler Capacity by Fuel Type**

Utility generating capacity, particularly that intended for base load use, represents a large capital investment which is recovered over a long service life. The design life for major generating units, including the boiler and turbogenerator components has traditionally been 30 to 40 years. This expected retirement age has lost much of its significance in the face of recent increases in new plant capital cost and tight new plant emission standards. Utilities are generally opting to extent the life of aging plants with large scale refurbishment or even repowering. Repowering introduces a new combustion technology, such as fluidized bed or combined cycle and can result in reduction emissions. In general, it is expected that larger units will be refurbished or repowered. Physical constraints, such as available space, may constrain the life extension options for a particular plant. Another important issue is the regulatory treatment of plants undergoing major reconstruction. Such plants may be treated as new sources and subject to more stringent emission limits (i.e., WEPCO decision).

The makeup of coal-fired capacity is of particular interest. Oil price increases of the last decade reversed the trend toward oil and resulted in conversion to coal except where availability or environmental constraints continue to favor oil or gas. Of the 67% of total boiler capacity identified as coal-fired, the percent of capacity built since 1965 is 62%. Ninety-eight percent of capacity was less than 40 years old in 1985. Figure 1-2 shows the age profile of coal-fired boilers.

## $SO_2$ Controls

As shown in Figure 1-3 98% of coal boilers are subject to $SO_2$ emission constraints. Currently, such constraints are met through the application of scrubbers or the use of sufficiently low sulfur fuel. This implies truly low sulfur coal only for those plants subject to NSPS level emission constraints. For coal-fired boiler capacity, 22% uses FGD and 9% reports the use of low sulfur fuel. More detail is provided in Figure 1-4.

As shown in Figure 1-5 a substantial amount of FGD experience has been accumulated, with a significant fraction of units installed before 1970, though most units have been installed since 1970. The most common commercial FGD systems utilize a venturi or a spray tower to introduce the reagent into the flue gas stream. A recent alternative for moderate removal efficiency is the spray dryer system, which minimizes the moisture content of the reagent resulting in a dry waste stream. The most common reagent are lime and limestone. Figures 1-6 and 1-7 summarize the relative share of these technologies for each age category. Limestone remains the most popular reagent with no substantial trend toward alternatives. Spray tower plants have displaced venturi plants for recent installations, and the spray dryer system has gained some market share.

## $NO_x$ Controls

Currently all nitrogen oxide controls in U.S. utility boilers are strictly combustion controls. No $NO_x$ scrubber technologies, such as selective catalytic reduction (SCR), are in use. Combustion controls limit the formation of "thermal" and fuel $NO_x$ by controlling peak combustion temperatures and limiting the availability of oxygen. A variety of combustion controls are available as described in a subsequent section. Low $NO_x$ burners are the dominant control technology; some 30% of coal-fired capacity employs some form of low $NO_x$ burner (see Figure 1-8).

Because of the sensitivity of $NO_x$ emission rate to combustion characteristics, several details of boiler design are important determinants of $NO_x$ emissions. Primarily, these relate to firing and slag removal systems. Wet bottom boilers, for which slag is

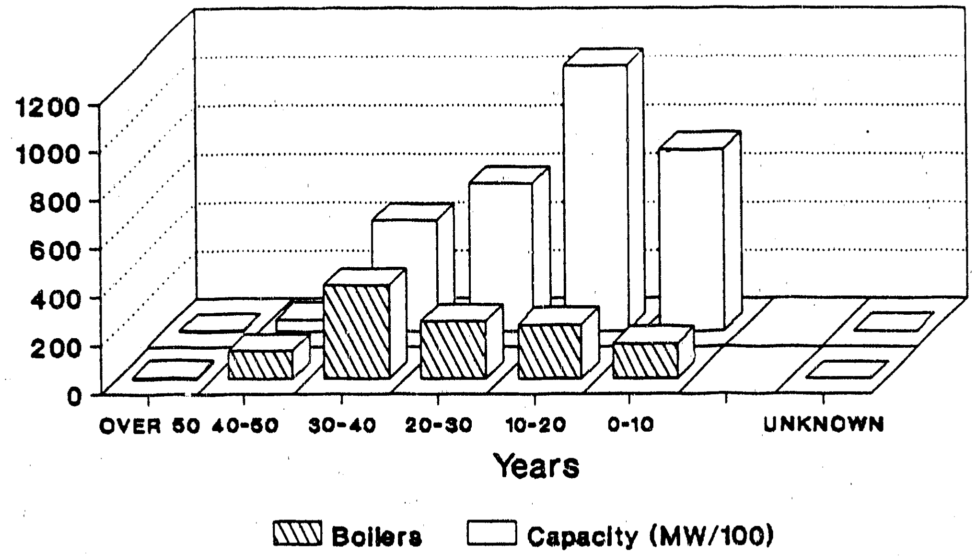


**Figure 1-2 Number of Coal-Fired Boilers and Boiler Capacity by Age**

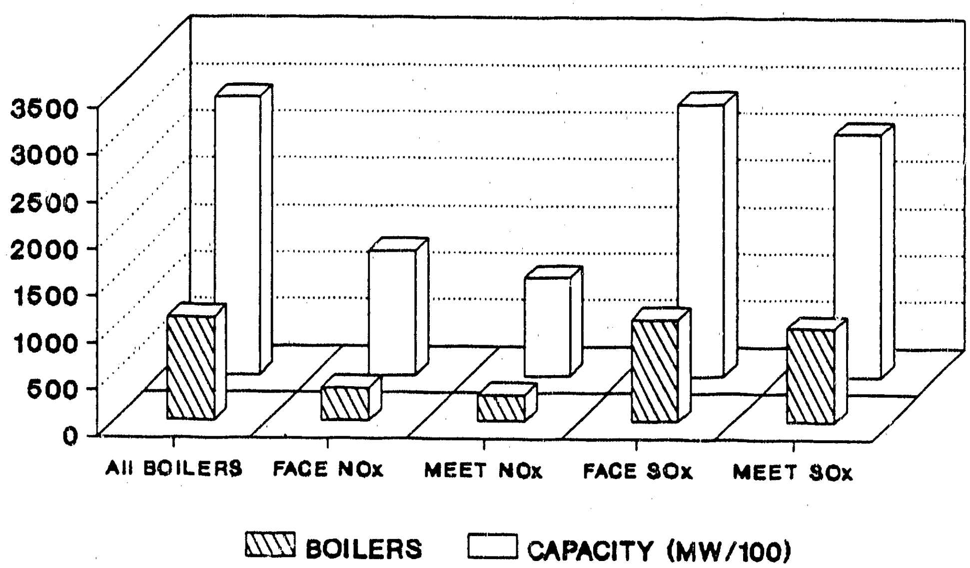


**Figure 1-3 Number of Coal-Fired Boilers and Boiler and Capacity Subject to $SO_2$ and $NO_x$ Emission Standards**

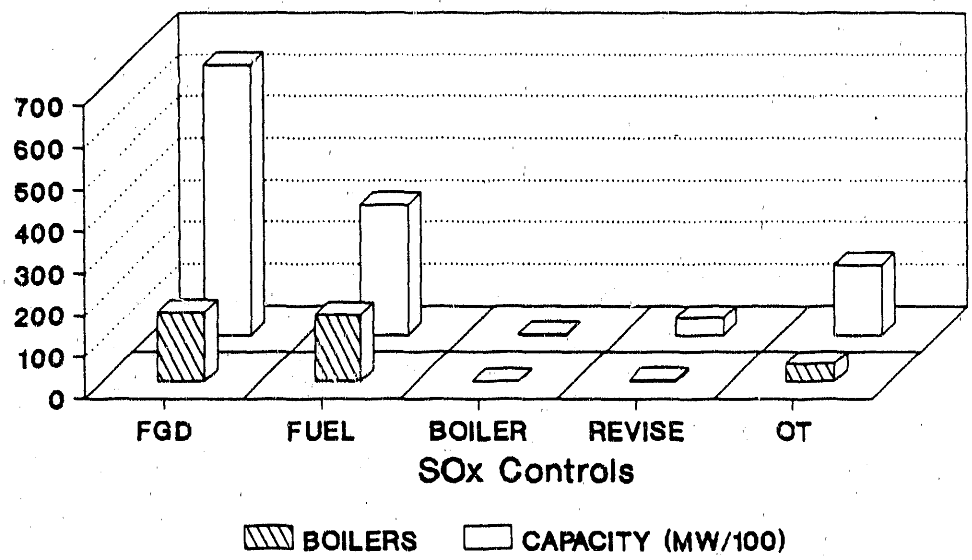


**Figure 1-4 Number of Coal-Fired Boilers and Capacity with $SO_2$ Controls**

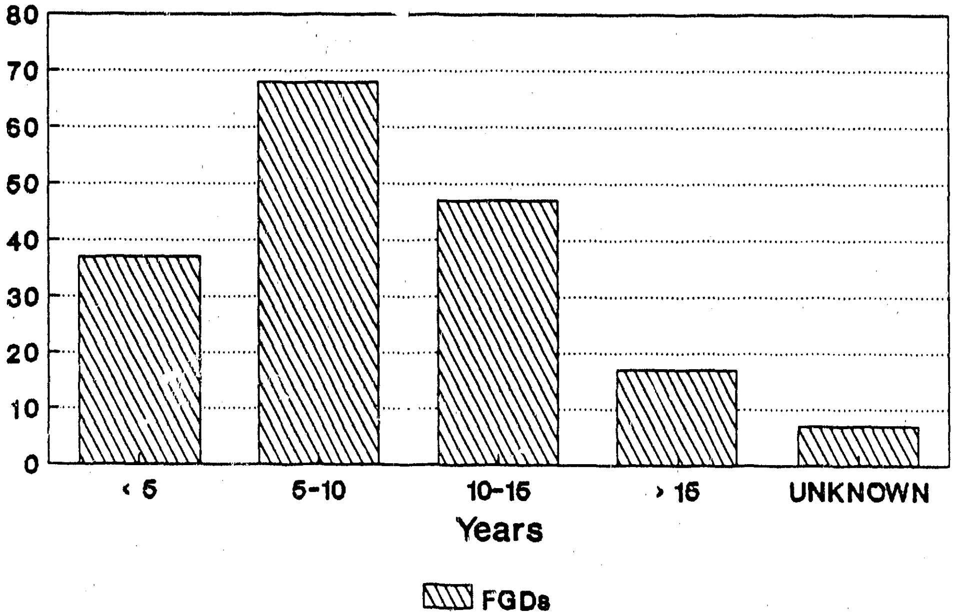


**Figure 1-5 Age of FGD Units**

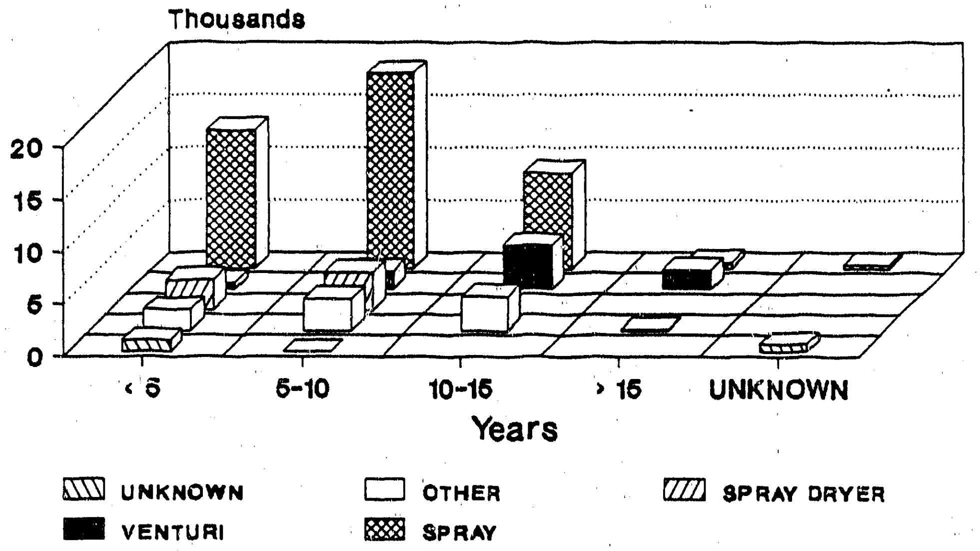


**Figure 1-6 Sum of Boiler Capacity (MW) by Age and FGD Type**

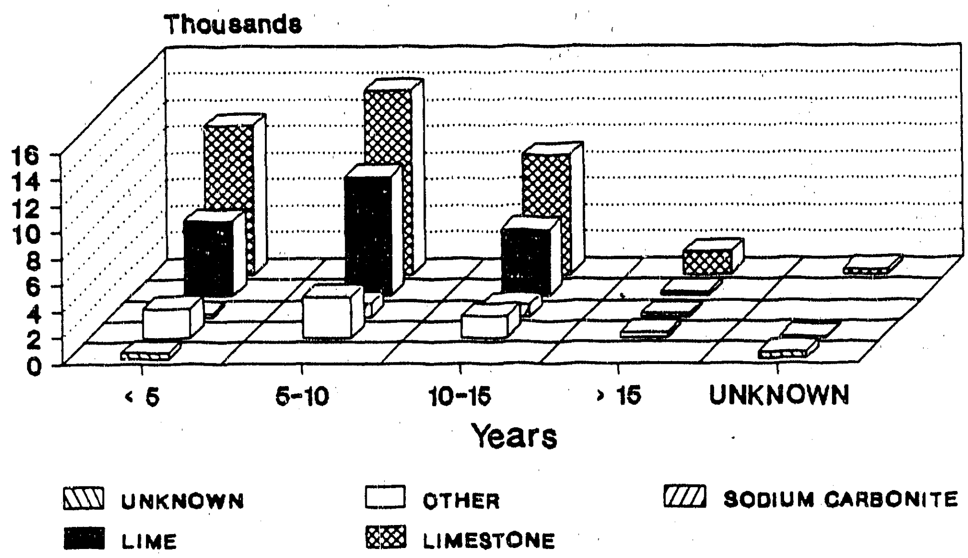


**Figure 1-7 Sum of Boiler Capacity (MW) by Age and Sorbent Type**

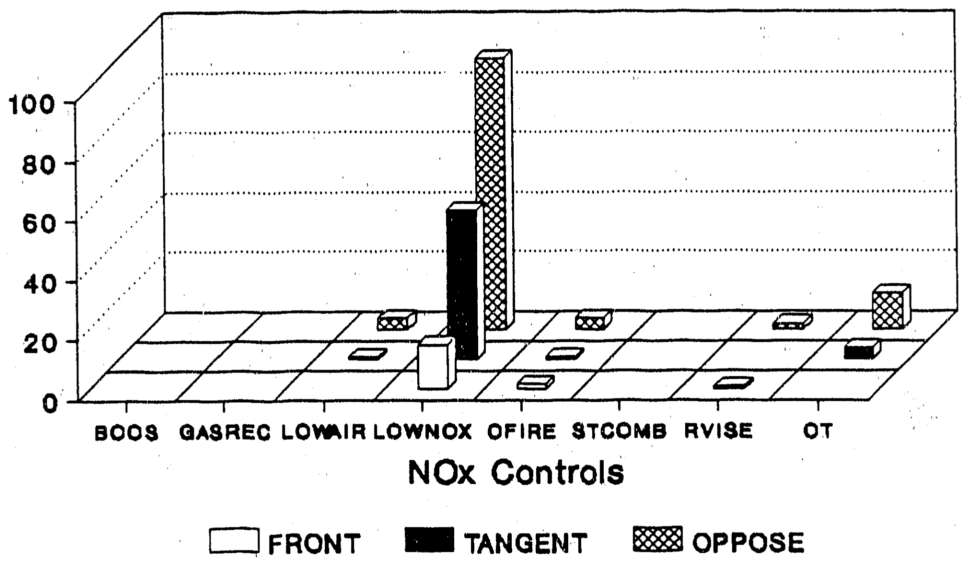


**Figure 1-8 Number of Coal-Fired Boilers and Capacity with $NO_x$ Controls**

removed in a molten state, have a 70% higher $NO_x$ emission factor than dry bottom boilers (AP42). The firing type generally refers to the orientation and location of burners in the furnace. They can be strictly front mounted, mounted on opposing sides, or tangentially from the corners. These options apply to pulverized coal combustors. For lump coal a stoker system is applicable. This is a little-used option in modern utility boilers. The cyclone furnace is capable of burning crushed coal. That is, pulverizing is not required. It has other advantages, including reduced fly ash production and small furnace size. However, the intensity of combustion in the cyclone furnace results in high $NO_x$ productions.

From Figures 1-9 and 1-10, it is clear that most capacity uses pulverized coal with either tangential or opposed firing and dry bottom slag removal. Interestingly, a shift from a preference from tangential firing to opposed firing can be seen in Figure 1-11. This trend is of some interest since for larger boilers (over 500 MW) opposed firing is inherently a more significant $NO_x$ emitter.

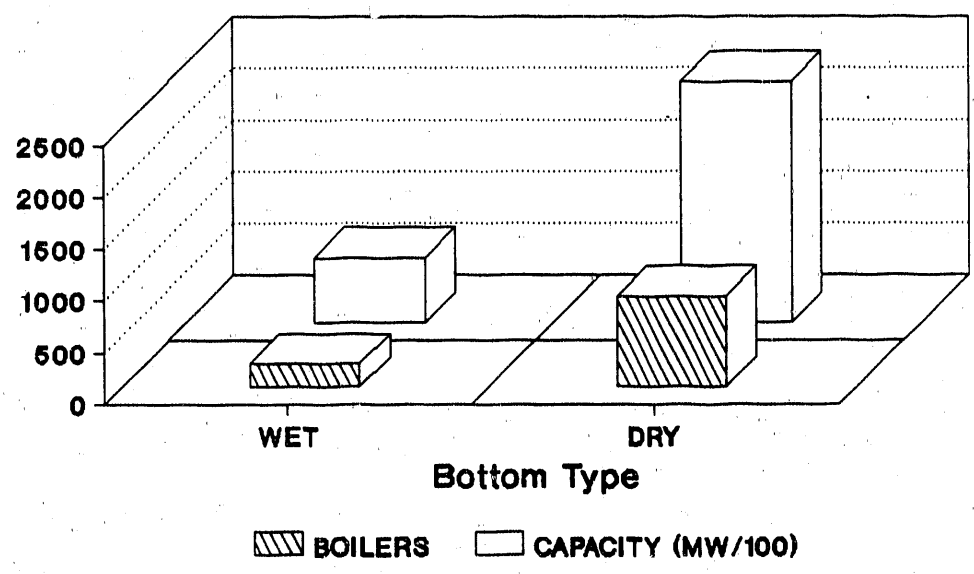


**Figure 1-9 Number of Coal-Fired Boilers and Boiler Capacity by Bottom Type**

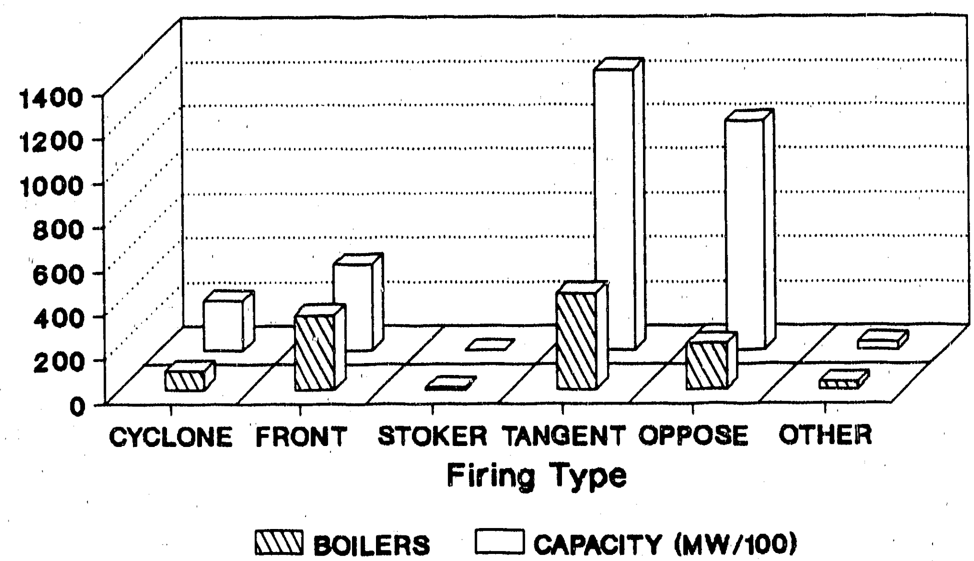


**Figure 1-10 Number of Coal-Fired Boilers and Boiler Capacity by Firing Type**

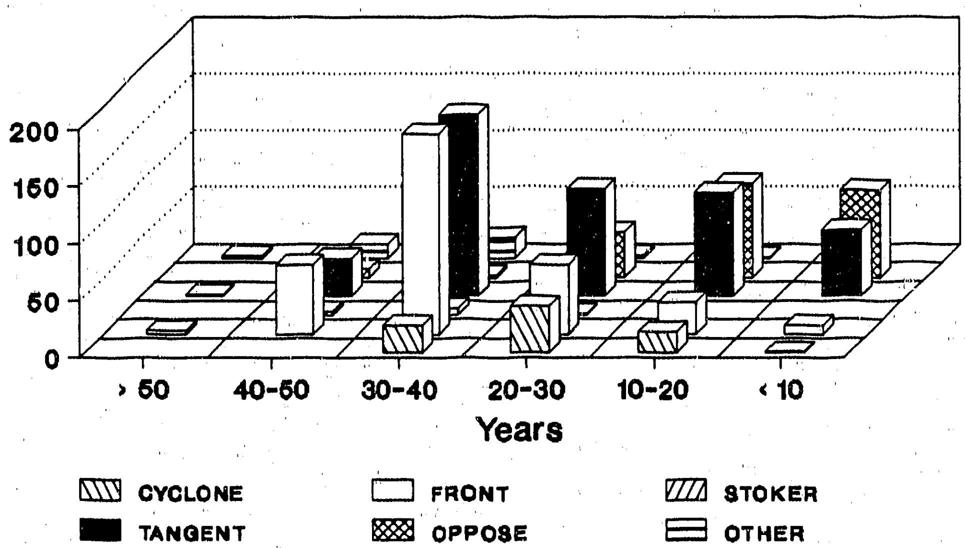


**Figure 1-11 Coal-Fired Boiler Capacity (MW/100) by Age and Firing Type**

Note also that the developing market for cyclone boilers has evaporated since the advent of constraints on utility boiler $NO_x$ emissions. The preferred $NO_x$ control method on coal-fired boilers for each firing type is shown in Figure 1-12.

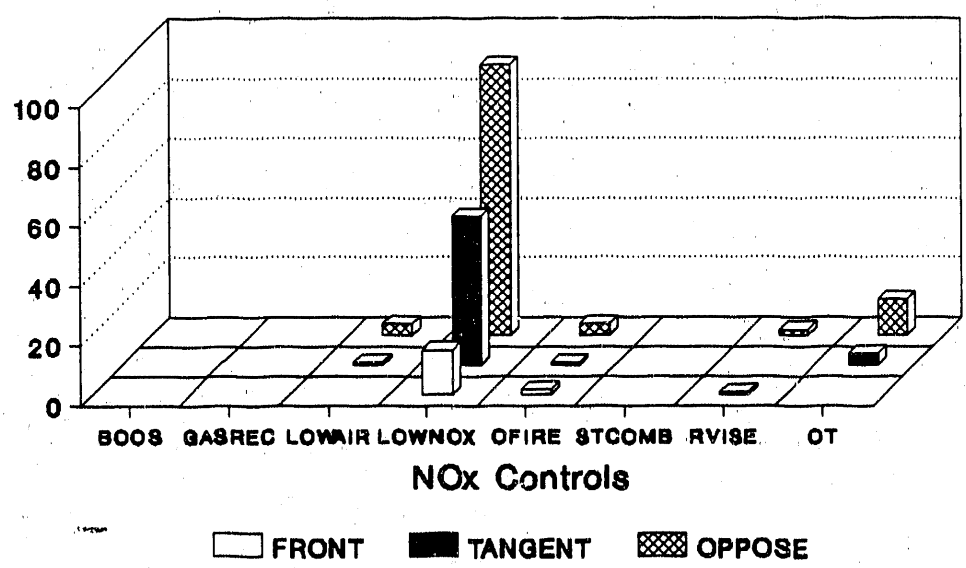


**Figure 1-12 Number of Coal-Fired Boilers with $NO_x$ Controls by Firing Type**

## 2.0 RETROFIT ISSUES FOR UTILITY BOILERS

Estimating the cost of retrofitting $SO_2$ and $NO_x$ controls on coal-fired utility boilers is difficult because of the diversity of boiler and coal characteristics and site-specific location factors. These factors include: boiler and plant location; scope adders; furnace type and configuration; and boiler and fuel characteristics. Table 2-1 shows which of these parameters have the greatest effect on the cost and performance of various $SO_2$ and $NO_x$ control technologies.

### 2.1 Boiler and Plant Location

Boiler and plant location factors which effect the cost and performance of retrofitting $SO_2$ and $NO_x$ controls are: labor and material rates, access and congestion, soil and underground obstructions, and flue gas ducting demolition/construction. Labor and material costs vary from state to state and city to city. In most regions of the country the cost index values are within +/-10 percent. However, some regions and cities have much higher labor and material cost index values. These areas typically have high population densities (northeast states, Michigan, Ohio, Chicago and Philadelphia areas, etc.). For example, if a plant in Wisconsin has a labor index value of 1.0, a plant in North Carolina would have an relative index value of 0.88 and a plant in Cleveland, Ohio a relative index value of 1.22.

Plant and boiler access and congestion have a significant effect on the cost of retrofitting many of the $SO_2$ and $NO_x$ control technologies. If access is limited by existing equipment, additional engineering and construction time is required to make difficult lifts or additional cost is incurred for relocating existing equipment items. In some instances, the additional construction time/difficulty may result in longer boiler outages as well as outages for the adjacent boilers. Site congestion also can effect equipment layout due to the need for a compact foot print. This increases costs due to increased engineering and construction time and support structure for stacking equipment items. Lack of adequate equipment laydown area during construction also increases engineering/construction costs. Access/congestion difficulty increases the cost of construction by 2 to 50 percent depending on the process area (equipment size) and the degree of difficulty.

Flue gas ducting effects the cost of most of the control technologies evaluated. For the FGD technologies, the need to install long flue gas duct runs to and from the absorber locations can be a significant cost adder, especially for absorber outlet duct runs which usually require special linings or alloy construction. For may boilers this is not a problem because the

## Table 2-1 Key Retrofit Cost and Performance Parameters

| | Key Retrofit Factors | | | Key Scope Adders | | | | Furnace Parameters | |
|---|---|---|---|---|---|---|---|---|---|
| Control Technology | Access and Congestion | Underground Obstructions | Flue Gas Duct Distance | Chimney or Liner | Demolition and Relocation | Additional Particulate Control | Wet to Dry Ash Handling | Type | Volume |
| L/LS-Flue Gas Desulfurization | X | X | X | X | X | | X | | |
| Lime Spray Drying | X | X | X | X | X | X | X | | |
| Coal Switching or Physical Coal Cleaning | | | | | | X | | X | |
| Furnace Sorbent Injection | | | X | | X | X | X | X | |
| Duct Spray Drying | X | | X | X | X | X | X | | |
| Low $NO_x$ Combustion | | | | | | | | X | X |
| Natural Gas Reburn | | | | | | | | X | X |
| Selective Catalytic Reduction | X | X | X | | X | | | X | |

FGD absorbers can be located near the existing chimney. However, for may boilers, the absorbers must be located 500 to a 1000 feet away to find adequate space available. There is also frequently a need to install flue gas ductwork when retrofitting selective catalytic reduction and new particulate controls. The increase in capital costs of 200 to 1000 feet of ductwork when retrofitting controls ranges from: 6 to 35 percent for FGD, 23 to 135 percent for particulate controls, and 12 to 70 percent for selective catalytic reduction.

Underground obstructions and soil conditions effect the cost of foundations for major equipment items. The most common underground obstructions found at coal-fired power plants are inlet/outlet cooling water lines and ash sluice lines. Soil conditions at many plants have poor load bearing capacity because the plants are located adjacent to bodies of water (sandy-silty soils and high water table). Also, at many plants the only space available are old ash ponds. This area would likely have poor load bearing capacity and may require excavation of the ash and replacement with better quality soil and use of pilings. Capital cost are frequently increased by 3 to 15 percent due to underground obstructions and soil conditions.

## 2.2 Additional Cost Items

Relative to new unit systems, retrofit of $SO_2$ and $NO_x$ controls frequently requires cost adders. These cost adders could include:

- new chimney or chimney liner,
- boiler reinforcement and damper modification,
- furnace pressure control systems,
- replacement ID fans or added booster fans,
- demolition of existing facilities and ductwork,
- ESP upgrades, and
- conversion of wet fly ash handling to dry ash handling.

Although, any one item does not result in a significant increase in capital costs, most retrofit situations will require several cost adders. For example, over 50 percent of the boilers evaluated at 100 coal-fired power plants would likely require demolition/relocation of existing equipment.

## 2.3 Particulate Controls

The capital needs for particulate matter (PM) control upgrades or retrofit of new PM controls adds significantly to the capital cost of lime spray drying, coal switching, and the sorbent injection technologies. Based on the NAPAP study for 100 plants, major ESP upgrades or new particulate controls would likely be required at half of the boilers evaluated. Access/congestion difficulty and new flue gas ductwork significantly increase the cost of new particulate controls or ESP enlargement. Major ESP enlargement or new particulate controls can increase the control technology capital costs by 30 to 100 percent.

## 2.4 Furnace Type and Configuration

There are many boiler/furnace firing types in commercial use: the predominate ones being: front-wall and opposed wall-fired (circular burners), tangential-fired, cell-fired, cyclone-fired, turbo-fired, and down-fired. Most research efforts have been focused on developing low $NO_x$ burners for wall-and tangential-fired boilers which are the predominate furnace firing types. Currently, there are low $NO_x$ burners commercially available for these types of boilers. Low $NO_x$ burners for cell burners are undergoing commercial endurance testing. The boiler parameters which most directly effect $NO_x$ reduction performance for all combustion modification techniques are heat release rate and furnace configuration dimensions and volume). Boilers with high heat release rates (small combustion zone volume) have high $NO_x$ emitting characteristics. Reduction of $NO_x$ formation is achieved by increasing the combustion zone volume, thus reducing the peak temperatures and $NO_x$ formation. Limitations to increasing the combustion zone volume are furnace depth and height relative to the burner locations. The larger the volume in and above the combustion zone, the greater the $NO_x$ reduction potential. Natural gas reburning and selective non-catalytic reduction (SNCR) techniques produce a reducing zone rich in hydrogen radicals in the upper furnace area which results in the conversion of $NO_x$ to nitrogen. Good mixing and residence time are the most important factors effecting the amount of reburn fuel or chemicals injected (ammonia or urea) and the $NO_x$ reduction potential. There are many other factors which effect the capital cost and performance of retrofitting low $NO_x$ burners, staged combustion, and SNCR controls including: load following and coal characteristics.

## 2.5 Boiler/Fuel Characteristics

When selecting emission control technology options, there are a number of boiler/fuel characteristics which effect the annual cost of control (yearly capital recovery, operating and maintenance costs). These characteristics include: pollutant emission levels, level of control, remaining life, future capacity factor, and combined treatment of flue gases from 2 or more boilers. The pollutant emission level and level of control effect the type of controls to be considered and the capital and operating cost of the control to achieve a desired reduction level. Typically, the higher the pollutant emission level and the higher the required emission reduction, the higher will be the annual cost of control (on a mills/kWh basis).

The remaining boiler life effects the time left to recover the capital cost of applying emission controls. Low capital cost control technologies are favored by boilers having a short remaining life (less than 10 years) and high capital cost control technologies are favored by boilers having a long remaining life (greater than 15 years). Boiler capacity factors have a similar effect. High capital cost controls are favored by high capacity factors and disfavored by low capacity factors. Typically, boilers with limited remaining life also have low capacity factors.

For many of the high capital cost controls (FGD and SCR), economies of scale play a major role in the control capital cost on a dollar per kW basis. For example, the $/kW cost of conventional FGD for a 200 MW boiler is 30.35 percent higher than for a 500 MW boiler. The flue gas from more than half of the boiler population are already combined into common chimneys or could be easily combined into a common control system. As such, the flue gases from three 200 MW boilers could be treated in a single 600 MW system instead of three 200 MW systems. However, many controls are designed for application into the existing furnace and duct work (duct injection) and combined into a common control system. As such, the flue gases from three 200 MW boilers could be treated in a single 600 MW system instead of three 200 MW systems. However, many controls are designed for application into the existing furnace or duct work (duct injection) and combined flue gas treatment is not feasible with these control technologies.

## 3.0 APPLICABILITY AND COST OF CONTROL OPTIONS

Table 3-1 presents estimated capital and annual costs for 200 MW and 500 MW coal-fired boiler retrofit applications for ten $SO_2$ and $NO_x$ control technologies. For the flue gas cleaning technologies, retrofit difficulty (space availability or reuse of existing equipment) is an important cost factor, and low and high retrofit difficulty cases were estimated. Boiler characteristics which will significantly effect the application of the emission control options include: fuel price differentials (FPD), boiler size (MW), capital recovery life (CRL), boiler capacity factor (CF), percent reduction, and retrofit space availability (RD). The boiler/fuel characteristics and the emission reduction targets and timing will significantly effect the optimal emission reduction options that are most likely to be selected for a particular boiler.

Inspection of Table 3-1, shows that there is a wide range in capital and annual cost of control. In general, the higher cost controls achieve greater levels of emission reduction. Table 3-2 qualitatively indicates which boiler/fuel characteristics favor application of each control option.

Fuel substitution and gas reburning can be characterized as having low to moderate capital and maintenance cost requirements and a moderate to high operating cost requirement. The operating costs are predominately associated with the difference in cost between the low and high sulfur fuels. Because the annual cost of these technologies are predominately due to operating costs, they are favored by boilers having a short remaining life, low capacity factors, small size, small fuel price differentials, and/or high FGD/SCR retrofit difficulty.

Wet and dry FGD systems and selective catalytic reduction controls can be characterized as having high capital, maintenance and operating cost requirements, but can achieve very high levels of reduction. These controls are favored by high emission reduction levels, long remaining boiler life, high capacity factors, and large system sizes (MWs).

Sorbent injection and SNCR technologies can be characterized as having low to moderate capital and maintenance cost requirements, moderate operating costs, and moderate emission reduction potential. These technologies are favored by high FGD/SCR retrofit difficulty, high fuel price differentials, and moderate reductions.

Overfire air and low $NO_x$ burners have low capital and maintenance requirements and very low operating costs. These technologies are favored by low to moderate $NO_x$ reductions where sufficient furnace volume exists to reduce the heat release rate.

**Table 3-1. Estimated Cost for Coal-Fired Utility Boiler $NO_x$ and $SO_2$ Control**

| Technology Description | Capital Cost Range $/kW | | Annual Cost Range mills/kW-H | |
|---|---|---|---|---|
| | 200 MW | 500 MW | 200 MW | 500 MW |
| $SO_2$ CONTROLS: | | | | |
| Wet FGD | | | | |
| low difficulty | 296-304 | 222-225 | 16.8-14.0 | 13.5-11.7 |
| high difficulty | 525-542 | 389-398 | 25.2-20.3 | 19.6-16.2 |
| Wellman-Lord | | | | |
| low-high difficulty | 402-702 | 284-549 | 16.8-23.9 | 13.8-18.8 |
| Lime Spray Drying[a] | | | | |
| low difficulty | 155-256 | 126-197 | 9.0-12.3 | 7.4-10.5 |
| high difficulty | 241-407 | 197-315 | 11.8-16.2 | 9.8-13.6 |
| Sorbent Injection[a] | | | | |
| low-high difficulty | 65-86 | 48-68 | 5.8-10.1 | 4.8-9.1 |
| $NO_x$ CONTROLS: | | | | |
| Overfire Air | 4.1 | 2.4 | 0.1 | 0.06 |
| Gas Reburning[b] | | | | |
| $1 fuel differential | 15.4 | 11.7 | 1.8 | 1.7 |
| $2 fuel differential | 19.3 | 15.6 | 3.6 | 3.6 |
| Low $NO_x$ Burners | 16.8 | 9.7 | 0.43 | 0.25 |
| $NO_x$ OUT | 10-12 | 7-10 | 2.01-2.05 | 1.92-1.98 |
| Selective Catalytic Reduction | | | | |
| low difficulty (3-7 year catalyst life) | 94 | 78 | 4.2-3.4 | 3.8-3.0 |
| high difficulty (3-7 year catalyst life) | 126 | 104 | 5.0-4.3 | 4.4-3.7 |

[a]Assumes reuse of existing particulate control.

[b]Based on 15 percent gas substitution.

Source: South, et al. (1990).

**Table 3-2. Boiler/Fuel Characteristics Favoring Control Application**

| Control Technology Option | Favorable Boiler/Fuel Characteristics | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | FPD | % RED | CRL | PCE | MW | CF | RD | Other |
| Fuel Substitution | S-M | S-M | S | M-H | S-M | L-M | M-H | |
| Wet FGD & Wellman-Lord | M-H | H | M-H | - | M-L | M-H | L | byproduct |
| Lime Spray Drying | M-H | M-H | M-H | H | M-L | M-H | L | |
| Sorbent Injection | M-H | L-M | L-M | M-H | S-M | L-M | M-H | |
| Gas Reburning | S-M | M | L-M | - | S-M | L-M | M-H | |
| OFA & LNB | M-H | L-M | L-M | - | - | L-M | M-H | |
| Urea/Ammonia Injection | M | M | L-M | - | S-M | L-M | M-H | |
| Selective Catalytic Reduction | M-H | H | M-H | - | M-L | M-H | L | |

Nomenclature:

FPD - fuel price differential (Small, Moderate, Large)
% RED - percent $SO_2$ or $NO_x$ reduction (Small, Moderate, Large)
CRL - capital recovery life (Small, Moderate, Large)
PCE - particulate control efficiency (Low, Moderate, High)
MW - size in Megawatts (Small, Medium, Large)
CF - annual capacity factor (Low, Medium, High)
RD - retrofit difficulty (Low, Moderate, High)

Source: South, et al. (1990).

## 4.0 CONCLUSIONS

If acid rain legislation is enacted, a broad range of $SO_2$ and $NO_x$ control technologies will be available for existing utility boilers. Retrofitting control technologies will present a broad range of engineering challenges because of the diversity of boiler and fuel characteristics and site factors. The selection of the lowest cost control option will be influenced by the characteristics of the legislation and the boiler/utility characteristics.

High emission reduction requirements for a particular boiler or utility system will require application of technologies or technology combinations which can achieve large emission reductions. These technologies include FGD and fuel substitution for $SO_2$ control and SCR and combined controls for $NO_x$.

Moderate emission reduction requirements for a particular boiler or utility system allows for much greater flexibility in technology application. Controls with moderate emission reduction potential ($SO_2$-sorbent injection and fuel substitution: $NO_x$-combustion modifications, SNCR, gas reburning) could be applied to all boilers or controls with high reduction levels could be applied to some of the boilers.

Low emission reduction requirements for a particular boiler or utility system would tend to favor control options which have low to moderate reduction potential. This would include fuel substitution for $SO_2$ control and combustion modifications for $NO_x$ control.

## REFERENCE

South, D.W., et al., 1990, *Technologies and Other Measures for Controlling Emissions: Performance, Costs and Applicability*, State of Science/Technology Report Number 25, National Acid Precipitation Assessment Program, Washington D.C. (January 1990).

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