Flue Gas Desulfurization Technologies for Coal-Fired Power Plants

Paul S. Nolan
The Babcock & Wilcox Company
Barberton, Ohio, U.S.A.

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Abstract

The control of sulfur dioxide emissions from thermal power plants is examined in light of the recent advances made in developing commercial processes for this application. Beginning with a discussion of some of the more recent developments in the conventional wet and dry scrubbing technologies, the paper provides a description of the results of the recent full-scale demonstration projects conducted on the lower capital cost furnace and duct sorbent injection technologies — Limestone Injection Multistage Burner (LIMB) and Coolside, respectively. In addition, the results of large pilot-scale research and development activities on the related Limestone Injection Dry Scrubbing (LIDS) and SO_x-NO_x-Rox Box (SNRB) processes are included. The paper concludes with a discussion of the economics of each of the processes based on U.S. installation.

Introduction

International awareness of environmental concerns has been increasing in recent years as economists forecast explosive growth around the world. Such predictions highlight the importance of minimizing the impact of increased air, water, and solid waste pollutants. One area that has received a considerable amount of attention is the concern about the potential for acid rain that results from the generation of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) during the combustion of fossil fuels. Particularly notable are the programs on flue gas desulfurization (FGD) technologies that have been ongoing in a number of countries for several years. Seeking to improve the effectiveness of SO_2 emission control, FGD research and development has progressed to the point that an array of processes are available to cover a broad range of site-specific, technical, and economic considerations.

Although modern FGD development received sporadic attention between the 1920s and the 1950s, broader-based, concerted efforts began in the 1960s and continue through the present. Within these last few decades, wet scrubbing with lime or limestone* slurries has come to be the dominant commercial FGD technology. Worldwide, there are currently 678 FGD systems operating on a total capacity of about 229 GW_e.[1] Approximately 79% of the units, representing 199 GW_e of capacity, are based on lime or limestone wet scrubbing. About 18% of the units, or about 25 GW_e, utilize either sodium-based or lime slurry (spray) dry scrubbing. The remainder use various regenerable processes or sorbent injection technologies of one form or another.

In the United States, coal-fired utility boilers have been the focus of much of the effort on emission control, since they represent a major source of SO_2 emissions. National standards for the control of SO_2 from utility boilers were first established in 1970, but were only applied to newly

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* In this paper, limestone refers to calcitic limestone (calcium carbonate), $CaCO_3$, and lime to calcitic hydrated lime, $Ca(OH)_2$. Reference is also made to dolomitic hydrated lime, $Ca(OH)_2 \cdot MgO$. The reader is reminded that calcination of $CaCO_3$ produces quicklime, CaO, also commonly referred to as calcined lime, which in turn is slaked to become calcitic hydrated lime. Dolomitic limestone, $CaCO_3 \cdot MgCO_3$, undergoes similar reactions to form analogous dolomitic compounds. The dolomitic hydrated lime can be further hydrated to $Ca(OH)_2 \cdot Mg(OH)_2$ under pressure. Although this material was used in some related studies, no specific references to it are included in this paper.

constructed units. Since many boilers built before these regulations continued to operate, and even now have a substantial number of years of useful life remaining, there was a need to address emissions in a more comprehensive manner. This was accomplished when the U.S. Congress passed the Clean Air Act Amendments (CAAA) of 1990.

Signed into law on November 15, 1990, the Acid Rain Provision of the CAAA effectively required SO_2 emission compliance in two phases for coal-fired boilers rated at 25 MW_e or more. Phase I, applying to 110 boilers that are among the largest utility sources, required emission levels of no greater than 1075 ng SO_2/J (2.5 lb/10^6 Btu) by January 1, 1995, with provision for a two-year extension for implementing ≥ 90% removal technologies under most conditions. With the addition of those units planned or under construction to meet the requirements, there will be a total of 366 FGD units in the U.S. operating on approximately 125 GW_e of capacity. Of these, approximately 75% are either lime or limestone wet scrubbers, 15% dry scrubbers, and 5% other technologies. The remainder are planned units for which the technology has not yet been selected.

Phase II of the CAAA effectively required boilers 25 MW_e and larger to have their emissions capped at 516 ng SO_2/J (1.2 lb/10^6 Btu), and that these reduced emissions be effective January 1, 2000. A four-year extension was available for implementing selected clean coal technologies. The end result of the CAAA is a national emission limit of 8.1 x 10^6 t (8.9 x 10^6 ton) of SO_2 by January 1, 2000. This represents a 9.1 x 10^6 t (10.0 x 10^6 ton) reduction from the 17.1 x 10^6 t (18.9 x 10^6 ton) emission level in 1980. (It is noted that, while FGD is one option available for U.S. utilities to comply with Phase I CAAA regulations, some utilities are switching to the use of lower sulfur coals and other fuels. The extent to which this is a viable alternative in Phase II will be determined by supply and demand considerations.)

The actual selection and application of any FGD technology for a specific site is the result of a careful examination of both technical and economic aspects. While it is generally recognized that high SO_2 removal efficiency has been responsible for the general popularity of wet and (spray) dry scrubbers, recent advances in developing lower capital cost sorbent injection processes have renewed interest in these FGD technologies. Moderate to high levels of removal have been demonstrated, indicating that these technologies can offer attractive alternatives over a broader range of conditions than originally thought.

Conventional Technologies

Babcock & Wilcox (B&W) has been an active participant in the development, demonstration, and commercialization of many of these technologies. With wet scrubber sales of 18,588 MW_e and dry scrubber sales of 2,740 MW_e,the company is one of the major worldwide suppliers of FGD systems. In addition, B&W has participated in four sorbent injection projects (one 5 MW_e and three ~100 MW_e demonstrations) sponsored by the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA). It is from this perspective that the balance of this paper seeks first to provide the reader with a background appreciation of some of the more important features of the conventional wet and dry scrubbers offered by B&W today. This forms the basis from which the development of the lower capital cost sorbent injection technologies proceeded. The paper goes on to describe the results of these efforts as the technologies begin to be accepted as fully commercial.

Wet Scrubbing

As noted earlier, lime and limestone wet FGD systems are the mainstay of SO_2 emission control throughout the world. In the U.S., passage of the Clean Air Act in 1970 promoted trials of various types of systems. It was not long, however, before the utilities and major system suppliers gravitated toward wet scrubbers in which SO_2 removal is accomplished by recirculating an aqueous slurry of lime or limestone in an absorber vessel to effect intimate contact with the flue gas.

The inherent simplicity, the availability of limestone, and the high removal efficiencies required by the law quickly advanced the popularity of this type of system. This occurred in spite of the fact that the early systems often relied on redundancy to overcome difficulties resulting from scale formation in the absorbers. In addition, they tended to incorporate a design that produced a thixotropic, waste sludge that was difficult to dewater to more than about 60% solids. The net effect was that the costs of these first-generation systems tended to be higher than they otherwise might have been.

Current state-of-the-art systems offer significantly improved performance compared to the first-generation FGD systems. Much of this is attributed to engineering designs developed to conform better with fundamental process chemistry. The largest single improvement has been the development of sulfite oxidation control. Scale formation in the early systems tended to occur as the result of uncontrolled crystallization of the naturally oxidized product calcium sulfate ($CaSO_4 \cdot 2H_2O$ [gypsum]) from the recirculating slurry. The blocky gypsum crystals typically represented 15 to 50 mol % of the absorbed SO_2 and, when intermingled with those of unoxidized calcium sulfite ($CaSO_3 \cdot 1/2H_2O$) platelets in the slurry, were responsible for much of the difficulty in dewatering. For limestone systems, blowing air into the slurry to force oxidation to near 100% provides seed crystals that minimize scaling, while at the same time producing more homogeneous slurries that dewater to concentrations in excess of 90% solids. For these reasons, the Limestone Forced Oxidation (LSFO) system has become the preferred technology worldwide.

The prime benefits of scale control derived from forced oxidation are greater scrubber reliability and availability. Confidence in the design and operation of these wet systems has risen to the point that a number of utilities in the U.S. and Canada are now specifying and/or buying single absorber systems, with no redundant absorber towers, to satisfy their compliance requirements. Figure 1 shows the primary components of the absorber towers currently being offered by B&W.

Three B&W scrubber systems are currently operating on high sulfur U.S. coal plants, producing gypsum for wallboard. FGD byproduct gypsum has also been used as an agricultural soil amendment and in cement manufacture.

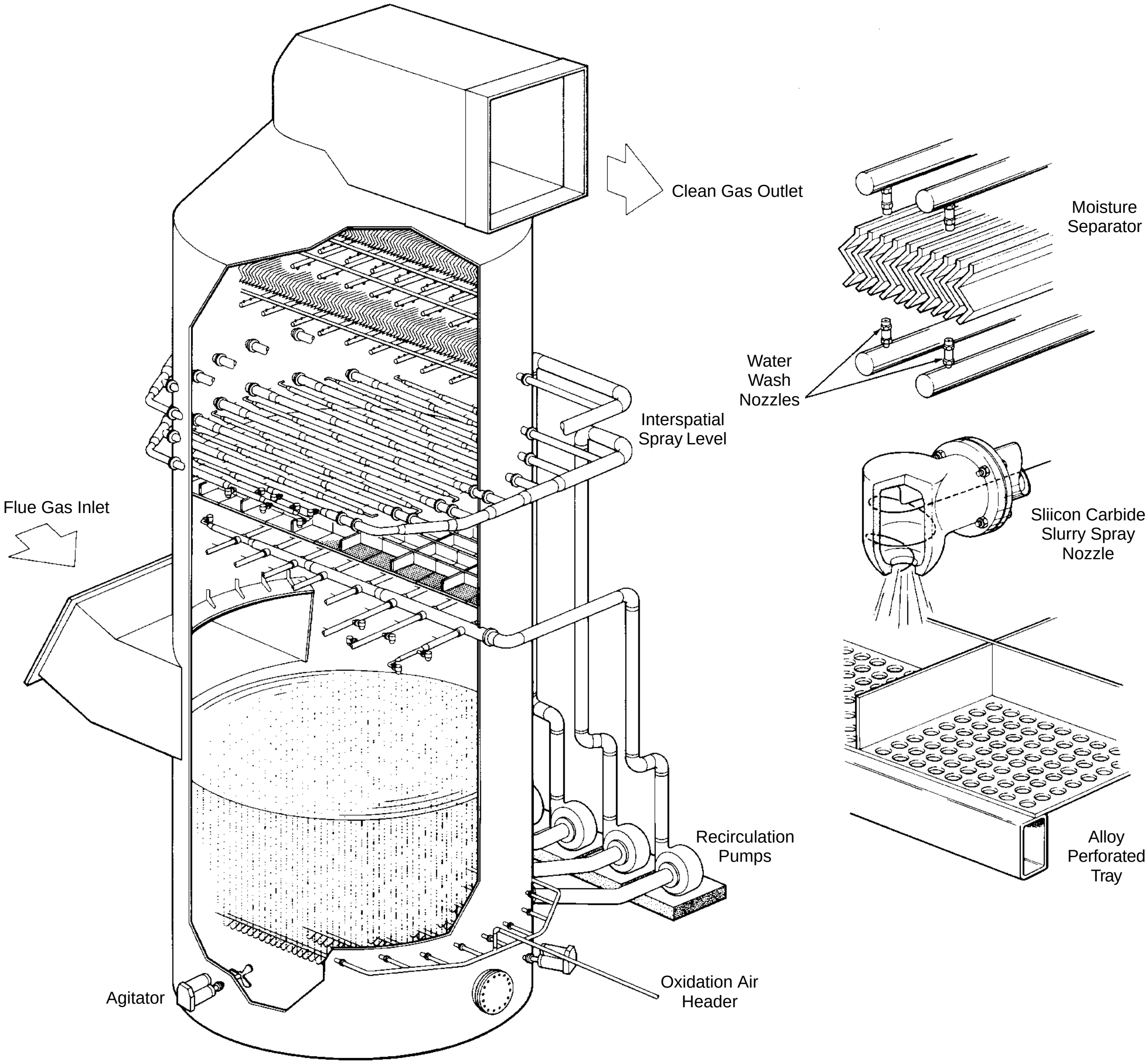

Figure 1 B&W wet FGD absorber tower.

Even if the gypsum is not sold, the enhanced dewatering capability makes the process attractive in congested areas because the gypsum is a stable landfill material that requires less area for waste disposal.

A variation of LSFO FGD systems used by a few utilities is the inhibited oxidation system. In this process, emulsified sulfur or sodium thiosulfate is added to the scrubber liquor to prevent oxidation to calcium sulfate, thus acting as a scale control agent. With low oxidation levels, the growth of larger calcium sulfite crystals produces enhanced dewatering benefits similar to those in the fully oxidized system. The inhibited oxidation system, therefore, enjoys the benefits of lower waste disposal cost and scale control. While it does not produce a usable end product, it does use less power than LSFO with minimal increased chemical cost.

Magnesium Enhanced Lime (MEL) scrubbers are another variation of state-of-the-art wet FGD technology, though they have not enjoyed the worldwide popularity of the LSFO FGD systems. They have, however, been systems of choice in the Ohio River Valley of the U.S., where over 8000 MW_e of MEL scrubbers are in operation. Most are located in a corridor from Pittsburgh, Pennsylvania, to Evansville, Indiana, although Units 1, 2, and 3 at the Four Corners Plant of Arizona Public Service also operate with MEL scrubbers. The Ohio River Valley MEL scrubbers use a reagent that naturally contains approximately 5% MgO. The Four Corners units use a locally blended lime product to achieve the same results.

MEL scrubber systems have proven capable of routinely performing at 98% SO_2 removal efficiency even on 3% to 4% sulfur coals, and do so in absorber towers that are significantly smaller than their limestone counterparts (Figure 2). The reason for this is that the presence of magnesium effectively increases the dissolved alkalinity, and consequently makes removal less dependent on the dissolution of the lime. To achieve the same effect, limestone-based systems require a high liquid-to-gas ratio (and there-

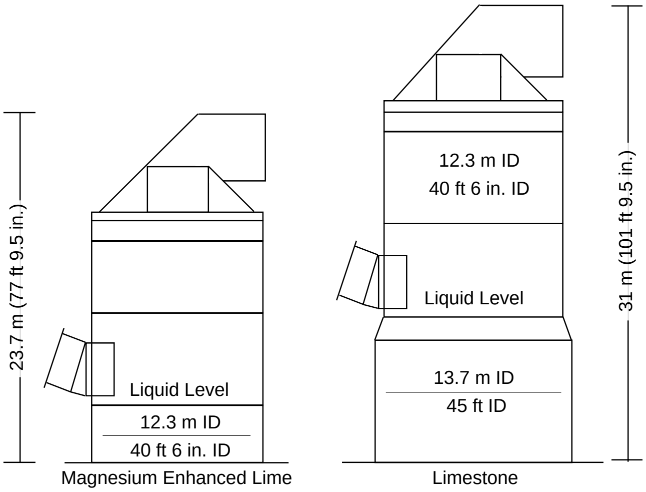

Figure 2 Sizes of MEL and LSFO absorber towers for a 250 MW_e unit.

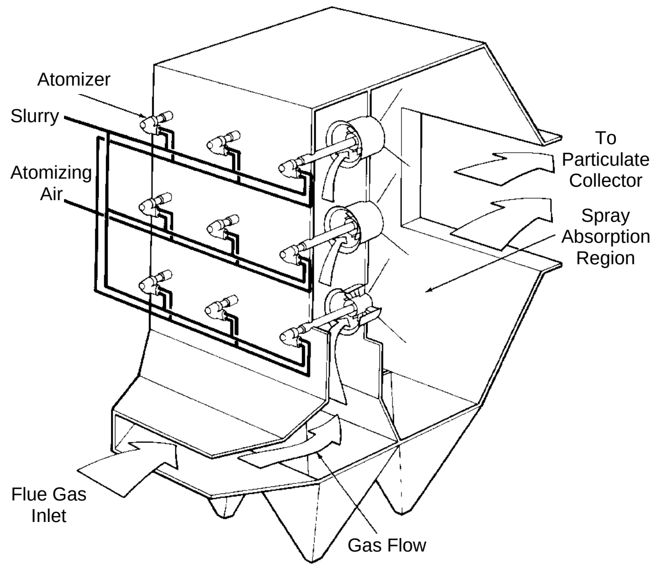

Figure 3 B&W dry scrubber module.

fore high power consumption), and sometimes the use of additives to approach the same removal efficiencies. The choice between LSFO and MEL systems has often been debated. Utilities have generally based their decisions on site-specific considerations dealing with the higher operating cost of lime, in comparison to the higher capital cost of the larger absorbers and greater pumping costs of LSFO FGD.

Finally, although the preceding discussion has concentrated on wet scrubbing with lime and limestone slurries, B&W has also supplied wet scrubbers for three 552 MW_e units where the reagent is a waste soda ash (Na_2CO_3) solution. The highly reactive soda ash allows these scrubbers to operate at even lower liquid-to-gas ratios. The application is highly site-specific, however, in that the utility is located close to a soda ash plant in an area where the net evaporation rate permits the product salts to crystallize in the disposal ponds.

Dry Scrubbing

Commercial utility installations using dry scrubber technology first appeared in the U.S. in the late 1970s and early 1980s. Derived from spray drying technology, this method of SO_2 emission control relies on the atomization of a sorbent – most commonly an aqueous lime slurry – in a reaction chamber upstream of a particulate collection device. Typically, the systems are designed to operate at a 15 to 25C (27 to 45F) approach to the adiabatic saturation temperature of the flue gas. The fine droplets absorb SO_2 and form the product calcium sulfite and sulfate as the water evaporates. The original B&W dry scrubber design in use at two utilities is shown in Figure 3. The design incorporates a patented, dual-fluid atomizer design that has proven to be particularly effective and durable. More recently B&W has been or is providing a rotary atomizer design for six additional units in the U.S. as a licensee of Niro A/S.

A downstream electrostatic precipitator (ESP) or baghouse collects the dry salts along with fly ash present in the flue gas. Use of a baghouse enhances the performance of the dry scrubber because additional SO_2 absorption occurs as the flue gas passes through the accumulated cake on the bags. Operation nearer the flue gas saturation temperature further promotes the increased removal efficiency obtained through the intimate contact in this configuration.

In the U.S., dry scrubber technology has primarily been used in retrofit applications on units burning low-sulfur coals. Required SO_2 removal efficiencies have normally been in the 80% or less range at inlet calcium/sulfur (Ca/S) ratios of 1.5 or less. There has been a great deal of discussion regarding the use of this technology on higher sulfur coals with higher removal efficiency. Such applications have not yet been demonstrated in the U.S., and it is anticipated that the primary commercial application of dry scrubbing in this country will continue to be with the low-sulfur fuels.

Advanced Technologies

While the wet FGD systems provided the benefits of high removal efficiencies, their relatively high capital cost made them unattractive for those applications where it was desirable to minimize the initial investment. In the late 1970s, interest in developing lower cost technologies heightened when one eastern U.S. utility determined that a 25% SO_2 removal technology, when combined with coal cleaning, would permit it to meet the regulated emission limit on one of its units. At about the same time, the U.S. EPA was continuing support of bench- and pilot-scale projects to develop low capital cost processes for many of the smaller and older units not regulated by the original Clean Air Act of 1970. Initially using limestone injection through staged low-NO_x burners, these studies went on to show that moderate levels of SO_2 emission control were possible by injecting sorbent within certain windows within a boiler's time-temperature profile. All this work culminated in a full-scale project, entitled "The Limestone Injection Multistage Burner (LIMB) Demonstration," which was conducted by B&W on the 105 MW_e Unit 4 boiler at Ohio Edison Company's Edgewater Station in Lorain, Ohio. The success of this project, and of a subsequent "LIMB Extension Project" sponsored by the U.S.

Department of Energy (DOE),* became an incentive for further improvements in the technology. Some of the techniques learned have been employed in related studies that have given rise to other sorbent injection processes, including:

- *Limestone Injection Dry Scrubbing (LIDS)* — a process in which limestone is first injected into the furnace, and the resulting excess calcined lime (CaO) is used as the reagent for dry scrubbing
- *Coolside* — a process that couples flue gas humidification with hydrated lime [$Ca(OH)_2$] injection into the duct downstream of the air heater
- *SO_x-NO_x Rox Box (SNRB)* — a process that combines hydrated lime and ammonia injection upstream of a hot, catalytic baghouse (Box) where the solid products calcium sulfite and sulfate and particulate (Rox) are removed, and the NO_x is reduced to nitrogen and water

Each of these technologies is described in more detail in the following sections. References to more complete reports on each technology are provided with the title of each section.

Furnace Sorbent Injection (LIMB)[2,3]

Furnace sorbent injection for SO_2 emission control was first attempted on a commercial scale in England in the 1930s, and was the subject of several studies in the U.S. in the late 1960s just before passage of the Clean Air Act. These early efforts, using limestone as the sorbent, typically produced low (20 to 30%) removal efficiencies that were generally regarded as less than adequate for the objectives set at the time. It was only when interest rekindled in the late 1970s and early 1980s that more detailed investigations determined how to overcome some of the chemical and mechanical limitations involved. The LIMB projects at Edgewater went on to demonstrate that furnace sorbent injection represents a low capital cost technology capable of achieving moderate levels of SO_2 control. As such, it is particularly applicable for older, smaller units burning lower sulfur coals.

The first (EPA-sponsored) LIMB project at Edgewater had the primary objective of attaining in excess of 50% SO_2 removal at an inlet Ca/S ratio of 2.0 while the unit burned 3% sulfur coal. To accomplish this, the project:

- undertook an extensive review of the literature to determine the limiting factors, both chemical and mechanical, thought to be responsible for the lower removals observed previously
- recommended and conducted further supporting studies in those areas where more information was required
- developed and installed a system accordingly designed for calcitic hydrated lime injection in that region of the upper furnace where the sulfation reactions would be maximized
- developed a humidifier design, based on B&W's dry scrubber experience, that not only overcame the adverse impact of sorbent injection on the electrostatic precipitator (ESP), but also provided a mechanism for enhanced SO_2 removal by being capable of operating at an 11C (20F) approach to the adiabatic saturation temperature of the flue gas

Figure 4 shows the LIMB process flow diagram as op-

* The Ohio Coal Development Office (OCDO) was the single largest sponsor of the LIMB demonstration projects at the Edgewater Station. The two projects came to be distinguished from one another by their co-sponsorship by EPA and DOE. Other major sponsors included Consolidation Coal Company (now CONSOL, Inc.) and B&W. Ohio Edison Company provided the Edgewater Station as the host site.

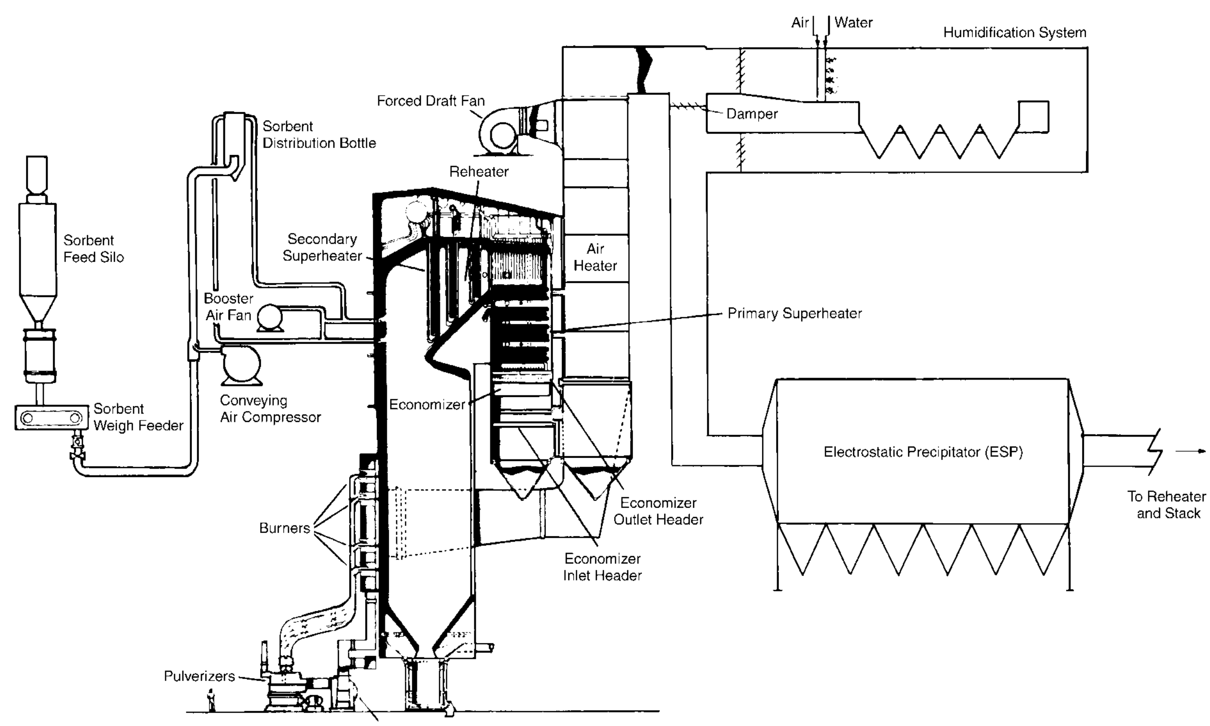

Figure 4 The LIMB process at the Edgewater Station.

erated at the Edgewater Station. The hoppers shown under the humidifier in the diagram were covered by steel plates throughout all testing, so that humidification was effectively carried out as an in-duct process. (The humidifier was constructed in a bypass loop over the hoppers of a retired ESP as a precautionary measure. If major ash deposits had formed as the result of humidification, this part of the process could have been isolated and hoppers used for removal. Fortunately, they were never needed.)

Following initial test results indicating SO_2 removal efficiencies in the 55 to 60% range, the project went on to demonstrate removals as high as 72% at a Ca/S ratio of 2.0. Humidification to a close approach to saturation added approximately 10% (absolute) to the removal efficiency. Tests also indicated that use of “ligno lime,” an enhanced calcitic hydrated lime, improved removal by about 7% (absolute). (This sorbent is a patented commercial calcitic hydrated lime doped with a small amount of calcium lignosulfonate.[4])

The DOE-sponsored LIMB Extension Project sought to demonstrate the generic applicability of the process by characterizing the performance to be expected for a variety of sorbents and coals. Sorbents tested included limestones reflecting three increasingly finer grinds, commercial calcitic and dolomitic hydrated limes, and ligno lime. Tests were conducted while the unit burned coals containing 1.6, 3.0, and 3.8% sulfur. Characteristic curves showing the relative importance of the more important variables are summarized in Figures 5, 6, and 7. [Note: These figures portray a first-order relationship between SO_2 removal efficiency and Ca/S ratio. This is approximately true over the range of conditions tested, as can be seen in Figure 7. A second-order fit with a diminishing increase in removal would describe the dependency more appropriately at higher stoichiometries.]

The effects of such variables as injector tilt, coal sulfur content, injection level (temperature), and momentum flux ratio (velocity) were also examined. Factors associated with the time-temperature profile (temperature and velocity) can, however, be system-dependent. It is believed that the relative insensitivity of the Edgewater system to these parameters was due to design near the optimal operating conditions.

The LIMB demonstration at Edgewater also provided an opportunity to observe the effects of furnace sorbent injection on boiler and ash collection and handling equipment operation. The increased dust loading associated with the process can cause additional ash accumulation on tubes. Depending on the amount of sorbent to be injected, and the number, capacity, and position of any existing sootblowers in a retrofit situation, it may be necessary to add sootblowers to clean convection pass surfaces. The LIMB ash was found to be as easily removed as normal fly ash. It was also observed that the hydrated limes had a much greater tendency to coat the tubes than did the coarsely ground limestone. While the opposite had been anticipated as the result of inertial impaction, it may be that the larger particles were self-scouring. There were no means available to establish any quantitative relationships, however.

The combined effects of a higher particulate loading,

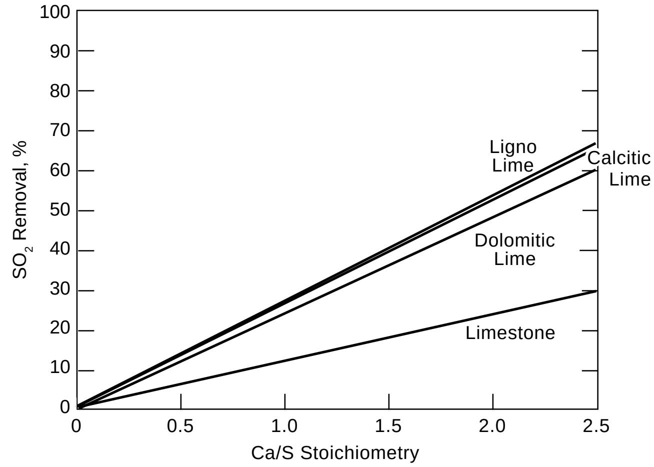

Figure 5 Effect of different sorbents on SO_2 removal while burning 1.6% sulfur coal and injecting at elevation 55.2 m (181 ft).

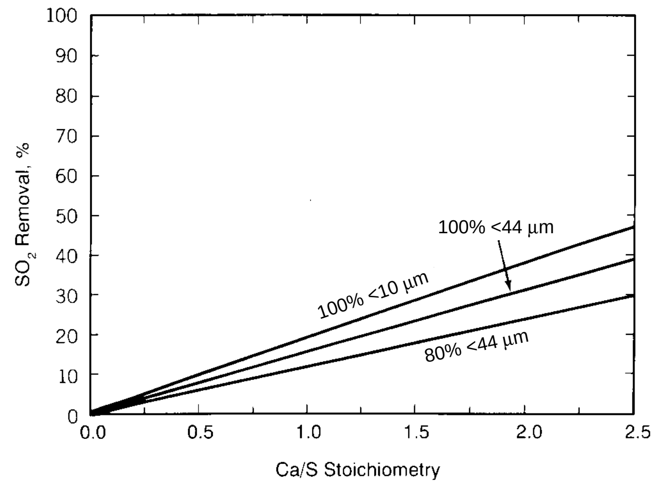

Figure 6 Effect of limestone grind on SO_2 removal while burning 1.6% sulfur coal and injecting at elevation 55.2 m (181 ft).

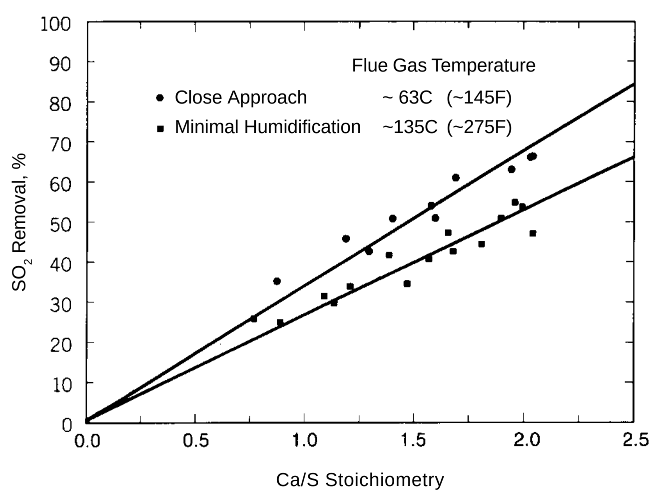

Figure 7 Effect of humidification on SO_2 removal.

an increased concentration of finer material in the case of injection of the hydrated limes, and increased ash resistivity all tended to degrade ESP performance. When operation was first attempted, it was quickly discovered that high ash resistivity gave rise to a back corona condition that was more severe than had originally been anticipated. Provision for the humidifier was already in progress, and once installed, proved to be an effective remedy as stack opacity returned to normal levels of a few percent. Other than this, the other main consideration that must by taken into account is that the ash collection and handling system must be designed or modified to accommodate the ash loading expected for the amount of sorbent injected and reacted.

The final observation regarding operation relates to the composition of the ash to be disposed. The ash collected downstream of a furnace sorbent injection process has a high quicklime content that must be taken into consideration. Collected as a dry by-product, it may find any of a number of uses ranging from being an additive for cement manufacture, to soil stabilization, to neutralization of acid mine drainage or other acid wastes.[5,6]

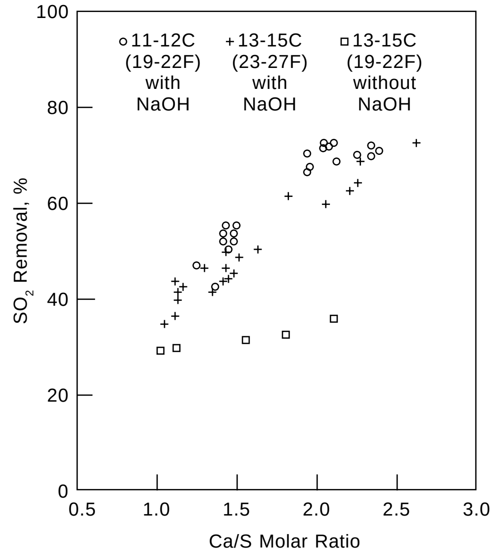

Figure 8 SO_2 removal for the Coolside process.

Duct Sorbent Injection (Coolside)[7]

Similar to the furnace sorbent injection systems, the duct sorbent injection systems utilize the duct between the air heater outlet and the particulate collector inlet to capture SO_2 with either lime- or sodium-based compounds. Limestone sorbents are quite unreactive in the 175C (347F) to 60C (140F) temperature range of interest for this technology. While the sodium-based systems can be effective,[8,9] concern over the solubility of the product salts in the waste effectively limits application to a few units in the western U.S. For these reasons, the balance of this discussion will focus on lime-based systems.

This alkali can be injected as a dry powder or as a slurry, but in either case, humidification to a close approach to the adiabatic saturation temperature of the flue gas is required for the process to be effective. The need to effect virtually complete evaporation of the water added makes it necessary either to have a long straight run of duct work, or to modify the flues for the residence time required. The length/size in turn depends on the degree of atomization achieved. Of course, the baghouse or ESP used for particulate collection must be adequately sized for the increased dust loading. The ash collected will contain a mixture of unreacted hydrated lime and fly ash, along with the product materials—calcium sulfite and calcium sulfate.

Duct sorbent injection systems have undergone extensive testing just within the past few years. The largest of these was performed as the Coolside process demonstration in conjunction with the DOE-sponsored LIMB extension project on the 105 MW_e unit at the Edgewater Station.[7] Initially developed by CONSOL Inc., the process entailed injection of dry calcitic hydrated lime at the inlet of the same humidifier that had been used during the LIMB demonstration. Most of the tests were conducted with the humidifier operating in the range of an 11 to 17C (20 to 30F) approach to the saturation temperature.

Lime utilization and SO_2 removal in the Coolside process are enhanced by the addition of sodium salts. For the Edgewater tests, caustic soda (NaOH) was added to the humidification water such that the sodium/calcium molar ratio was raised to as high as 0.2. Figure 8 depicts typical performance achieved in the course of the Coolside process tests. Although the added NaOH was directly responsible for some of the SO_2 removal, results indicate that the sodium salts improve lime utilization, presumably because their hygroscopic nature maintains a humid environment in the vicinity of the particles. Similar behavior was noted during CONSOL's pilot tests with neutral sodium salts added.[10]

The U.S. DOE 12 MW_e Duct Injection Test Facility at Ohio Power Company's Muskingum River Station has been the site of studies on lime slurry injection in ducts.[11] SO_2 removal efficiencies have been reported to be generally comparable to those achieved in the Coolside tests. More direct comparison is impossible at this point given the different scales of the tests, the preponderance of Coolside tests with sodium addition, and the fact that the Coolside tests were generally run at a closer approach to the flue gas saturation temperature. Nevertheless, the results suggest that the lime slurry is somewhat more reactive than dry lime. The advantage may be offset, however, by the need for a somewhat more complex delivery system, and the potential for greater abrasion in the slurry system.

Because much of the work on duct sorbent injection has been done so recently, no U.S. utility currently has a permanently installed, commercial system operating. There have been a number of inquiries, however, and international interest appears to be growing. Many seem to like to compare furnace sorbent injection with the duct injection. Since the removal efficiencies attainable by the processes are approximately equivalent, the primary considerations for the two technologies are summarized as follows:

- *Furnace Sorbent Injection*

- Significant SO_2 removal does not depend on a close approach to the adiabatic saturation temperature of the flue gas, although some degree of humidification may be necessary in order to keep an ESP operating properly
- Installing or upgrading of sootblowers to maintain boiler performance may be needed depending on the sorbent type and feed rate
- Requires provision for safe handling and disposal of ash containing quicklime (CaO), if not being used as a byproduct

• *Duct Sorbent Injection*

- Requires a close approach to the adiabatic saturation temperature of the flue gas, which in turn tends to require sufficient power for fine atomization and space for droplet evaporation
- Because it is run at close approach temperatures, the process has a greater tendency for forming deposits in the duct if not designed and operated properly
- Produces a dry product that does not contain quicklime, but does contain calcium sulfite which can present a chemical oxygen demand upon disposal

Limestone Injection Dry Scrubbing (LIDS)[12]

Experience with both dry scrubbing and furnace sorbent injection prompted B&W to integrate the two into the LIDS process, as it offered the advantages of combining the use of the lower cost limestone sorbent with higher overall SO_2 removal and sorbent utilization. Figure 9 shows the flow diagram of the process with particulate collection by either a baghouse or an ESP. In the process, injection of limestone into the furnace effects SO_2 removal as represented in Figure 6. The unreacted quicklime continues through the system until it is collected in the baghouse or ESP. Depending on the SO_2 removal efficiency desired, a portion of the collected ash is slurried with water through an appropriately sized slaking device. The slurry is then fed to the dry scrubber where the bulk of the SO_2 removal occurs. Significant additional SO_2 removal may also occur during particulate collection, especially if the flue gas must pass through a baghouse at a temperature relatively close to saturation.

McDermott Technology, Inc. (formerly B&W's Research and Development Division) carried out the LIDS tests at its Alliance Research Center in Alliance, Ohio. A major portion of the facility already existed as a pilot-scale combustion furnace called the small boiler simulator (SBS). Rated at 1.8 MJ/s (6.0 x 10^6 Btu/hr), the SBS had much of the auxiliary equipment in place as the result of earlier furnace sorbent injection tests. To this was added a cylindrical, down-flow dry scrubber designed for testing with gas residence times in the 5 to 10 s range. Its dimensions were 9.1 m (30 ft) high and 1.5 m (5 ft) in diameter. The baghouse contained 46 Nomex bags 3.0 m (10 ft) long and 12 cm (4.6 in.) in diameter, providing a design air-to-cloth ratio of 51 m/hr (2.8 ft/min) at 66C (150F).

The cost of achieving continuous operation to achieve true steady-state conditions made simulation of recycle necessary. This was accomplished by operating the pilot in a batch mode, and collecting the ash produced each day for preparation of the following day's slurry in a 7.57 m^3 (2000 gal) stirred tank. Recycle ratios, defined in terms of mass of recycled ash per mass of fresh sorbent, ranged from 0.4 to 1.9 for the tests conducted.

The LIDS test program characterized the SO_2 removal efficiency over a range of stoichiometries and approaches to the saturation temperature. The results are summarized in Figures 10 and 11 which show the overall removals obtained at the outlet of the dry scrubber and the baghouse, respectively.

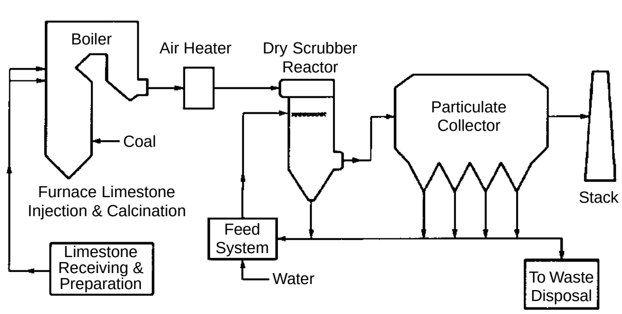

Figure 9 LIDS process flow diagram.

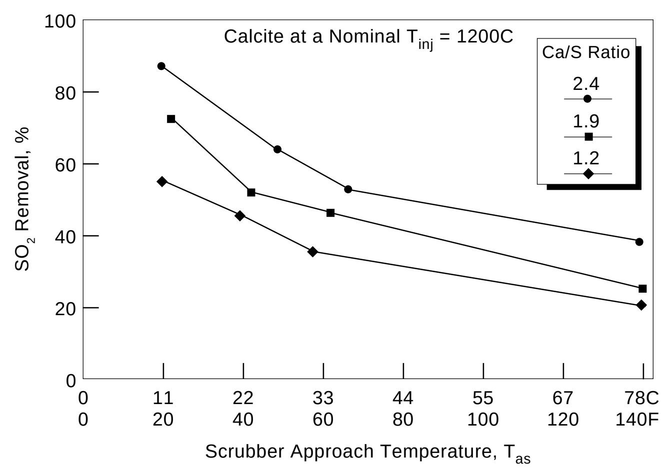

Figure 10 LIDS combined furnace and dry scrubber SO_2 removal.

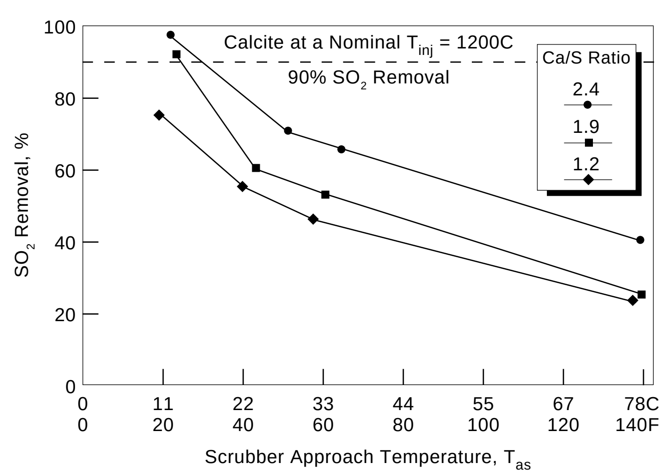

Figure 11 LIDS combined furnace, dry scrubber, and baghouse SO_2 removal.

The next step in the commercialization of the LIDS process is demonstration on a larger scale. B&W is currently looking for a suitable new or retrofit application at either an industrial or a utility site. Ideally, the candidate unit would be 50 to 100 MW_e in size, and have, or plan to have, a baghouse for particulate collection. This would permit demonstration of the maximum capabilities of the process and confirm scale-up criteria. Commercialization beyond this would be driven by normal market demands.

SO_x-NO_x-Rox Box (SNRB)[13]

B&W is developing the SNRB process as a combined SO_x, NO_x, and particulate (Rox) emission control technology by which all three pollutants are removed from flue gas in a high-temperature baghouse. SNRB incorporates lime- or sodium-based sorbent injection to capture SO_x, selective catalytic reduction (SCR) of NO_x by ammonia (NH_3), and particulate removal in a high-temperature, pulse-jet baghouse, as depicted in Figure 12.

McDermott Technology, Inc. conducted early tests in a 1500 Nm^3/hr (2500 acfm) pilot at the Alliance Research Center. Encouraging results led to a DOE Clean Coal Technology demonstration project which uses a six-compartment unit capable of treating 19,900 Nm^3/hr (30,000 acfm) of flue gas (equivalent to about 5 MW_e). Each compartment contains 42 full size bags that are 6.1 m (20 ft) long and 15.9 cm (6.25 in.) in diameter. Because the bags and SCR catalyst assemblies are full size and the unit is operated with a rotating cleaning cycle, scale-up will primarily involve multiplying the number of units required for the intended application. The project, co-sponsored by the Ohio Coal Development Office (OCDO) and the Electric Power Research Institute (EPRI), was conducted at Ohio Edison's Burger Station.

The tests concentrated on characterizing SO_2 removal with calcitic hydrated lime injected at various temperatures and stoichiometries. Results indicate that inlet Ca/S ratios near 2.0 reduce SO_2 emissions by 80 to 90%, well beyond the original 70% goal. Part of this is ascribed to more complete conversion in the baghouse than anticipated, although the removal appears to be sensitive to the baghouse temperature (Figure 13).

Results on NO_x and particulate emissions control have also been promising. Figure 14 shows typical data being developed on NO_x reduction for the process. Removal efficiency in excess of 90% has been achieved near NH_3/NO_x stoichiometry of 0.85. At the same time "ammonia slip," a term describing the undesirable bypass of unreacted NH_3, has generally been measured at levels of less than 4 mg/Nm^3 (5 ppmv).

Particulate emissions have averaged 7.7 ng/J (0.018 lb/10^6 Btu), well below the Clean Air Act's New Source Performance Standard of 12.9 ng/J (0.03 lb/10^6 Btu). This level of control equates to an average removal efficiency of 99.89% for the range of dust loadings and temperatures tested.

As was the case for the LIDS process, the next step toward full commercialization of the SNRB process is a larger scale demonstration of perhaps 50 to 100 MW_e. Again, a new or retrofit application would be suitable at either an industrial or a utility site.

Economics of the Processes

A summary of the economics of so many processes, particularly when they represent all stages of development from pilot-scale through commercial full-scale, must naturally be built upon a broad range of assumptions that the reader is reminded to consider in interpreting what follows. The approach taken uses the basis of the capital and operating costs developed for the LIMB and Coolside processes as they relate to the LSFO FGD process. The economic analysis employed was quite thorough and conformed to practices generally accepted by the U.S. utility

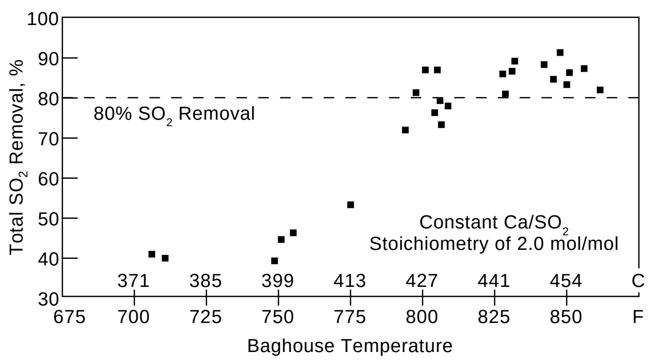

Figure 13 SNRB SO_2 removal.

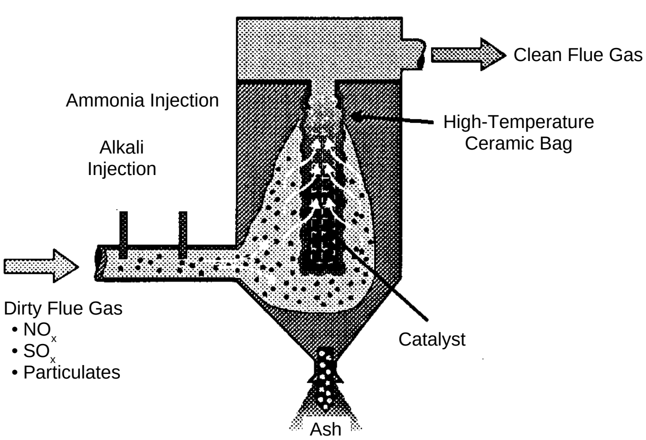

Figure 12 The SO_x-NO_x-Rox Box (SNRB) process.

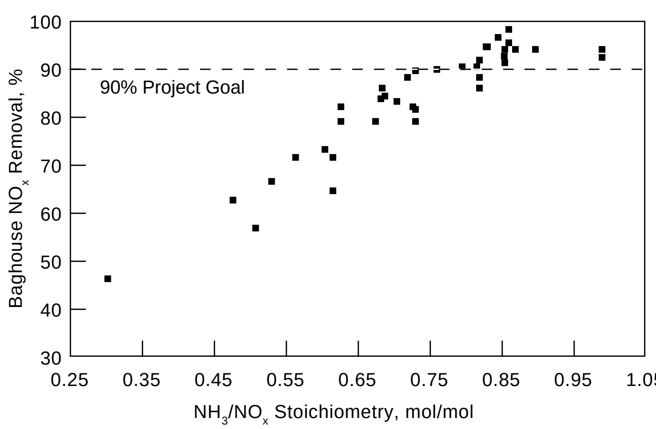

Figure 14 SNRB NO_x removal.

industry. For a description of the assumptions made, the reader is referred either to the full report [3] or to a somewhat abbreviated summary.[14] All capital costs are expressed in terms of U.S. dollars/kW, and annual levelized costs in U.S. dollars/ton of SO_2 removed. While this facilitates comparison, the reader is cautioned that not all the analyses start with the same basic assumptions. Rather, the values should be interpreted more properly as representing each technology in a reasonably favorable application of its capabilities.

The capital costs associated with LSFO FGD and with furnace and duct sorbent injection, as represented by LIMB and Coolside as practiced at Edgewater, are shown in Figure 15 for unit sizes in the range of 100 to 500 MW_e. The costs represent units burning a bituminous coal with a heating value of 27.7 MJ/kg (11,872 Btu/lb), and containing 2.50% sulfur and 10.77% ash (all as-fired values). Capital costs are similar for 1.5 and 3.5% sulfur coals, since basic equipment sizes are not that much different.

In contrast to the relative insensitivity of capital costs to coal sulfur, annual levelized costs which reflect operation over the life of the plant vary considerably with coal sulfur, as can be seen in Figures 16, 17 and 18. Examination of these figures also reveals that, while the cost per ton of SO_2 removed decreases with increasing coal sulfur, the decrease for LSFO FGD is much more dramatic than for the sorbent injection technologies. The main reason for this is the greater sorbent utilization in the wet technologies. For the same reason, the analysis shows why the lower capital cost sorbent injection technologies tend to be favored for the older, smaller plants where moderate levels of SO_2 are needed. (As described earlier, the costs of MEL wet scrubbers are equivalent to those for the limestone systems in general. However, site-specific factors can be very influential in decisions between the two.)

The other notable feature that appears within Figures 15 through 18 is the higher cost of the Coolside process in comparison to that of LIMB. Much of this is attributed to the cost associated with the purchase and operation of the fairly large compressor required for fine droplet atomization to achieve a close approach to the flue gas saturation temperature. For the same reason, the costs of duct injection of a slurry, while not specifically studied, would be expected to be comparable.

The economics of lime-based dry scrubbing are fairly well established since the process is commercial. However, there has been no recent study that provides as much detail as provided on LSFO FGD and the sorbent injection technologies. Nevertheless, the industry tends to think in terms of the costs of dry scrubbing being approximately 80 to 90% of LSFO FGD. This is reflected in an independent study[15] that showed an estimated capital cost of \$170/kW and an annual levelized cost of \$490/ton of SO_2 removed for a 300 MW_e unit burning 2.6% sulfur coal. This same study estimated the comparable LSFO FGD capital cost at \$210/kW and the annual levelized cost at \$550/ton of SO_2 removed, approximately equivalent to the figures determined in the B&W study.

The economics of the LIDS and SNRB processes are not as well established as those just described, since their development is ongoing. At this point in time, the capital cost of the LIDS process is estimated to be approximately equivalent to that of conventional dry scrubbing under the rough assumption that the cost of the limestone preparation and feed system is about equal to the pebble lime (commercial quicklime) slaking and pumping system. The lower cost of limestone, as compared to lime, is expected to generate savings in the annual levelized cost, however. Using a \$40/ton cost differential in an economic model similar to that used in the study referred to above, one might expect an annual levelized cost savings of about \$70/ton of SO_2 removed.

SNRB economics are the least refined of all the processes discussed due to the fact that many of the costs

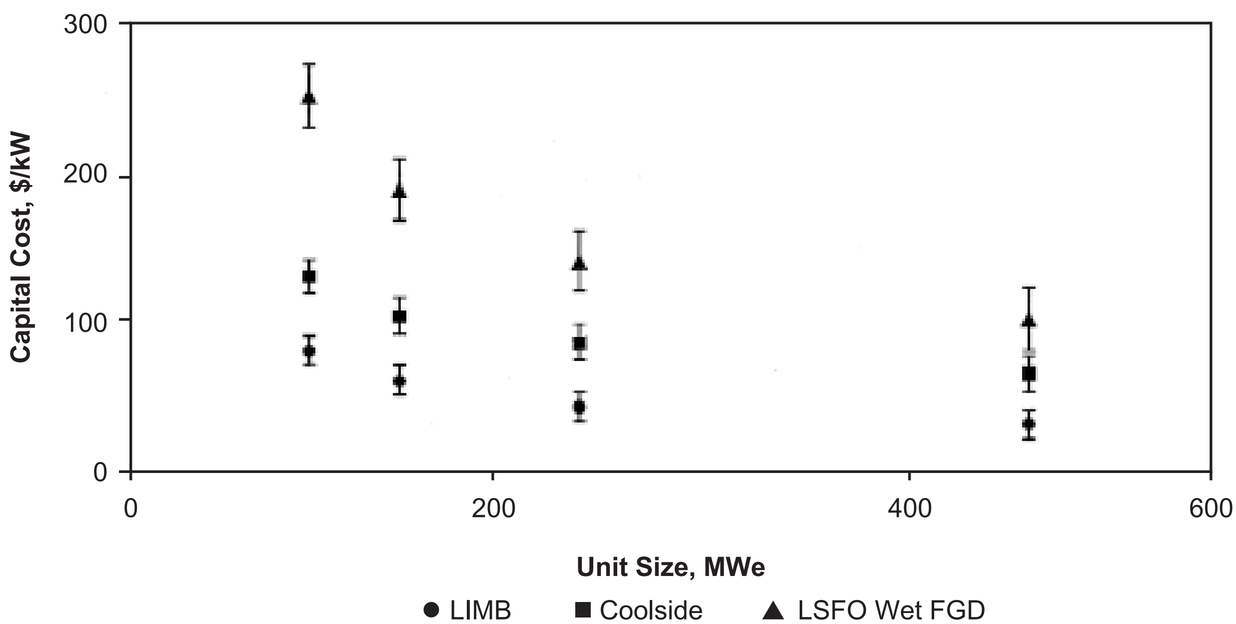

Figure 15 Capital cost in the U.S.A. for 2.5% S coal.

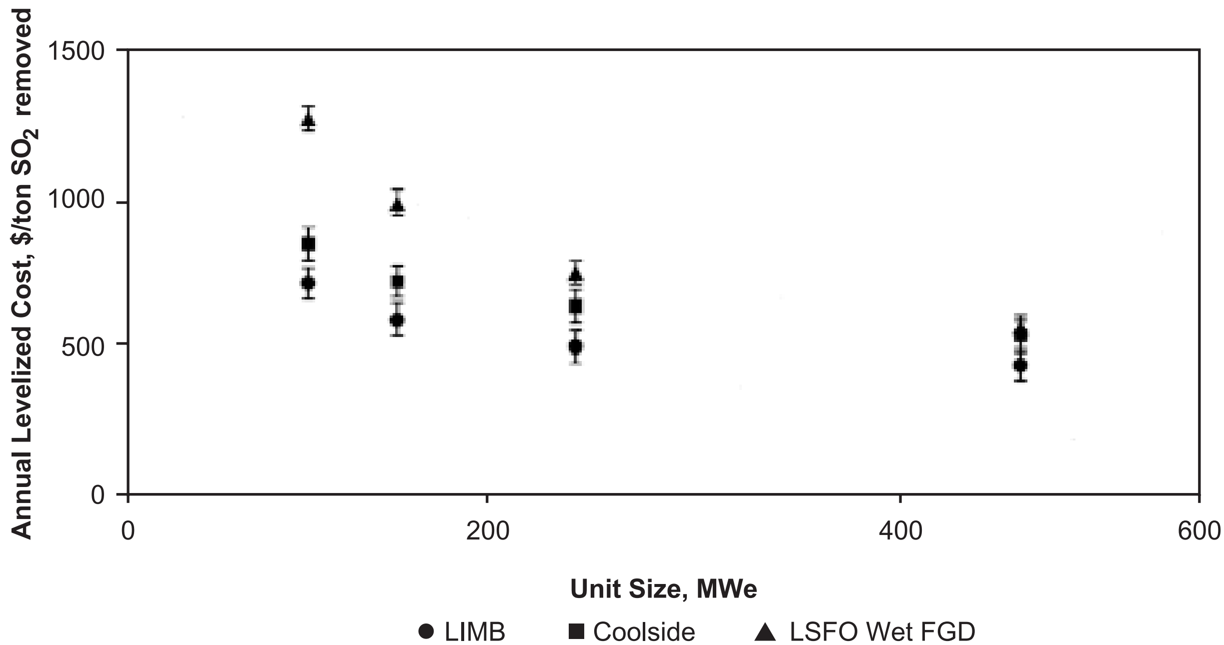

Figure 16 Annual levelized cost in the U.S.A. for 1.5% S coal.

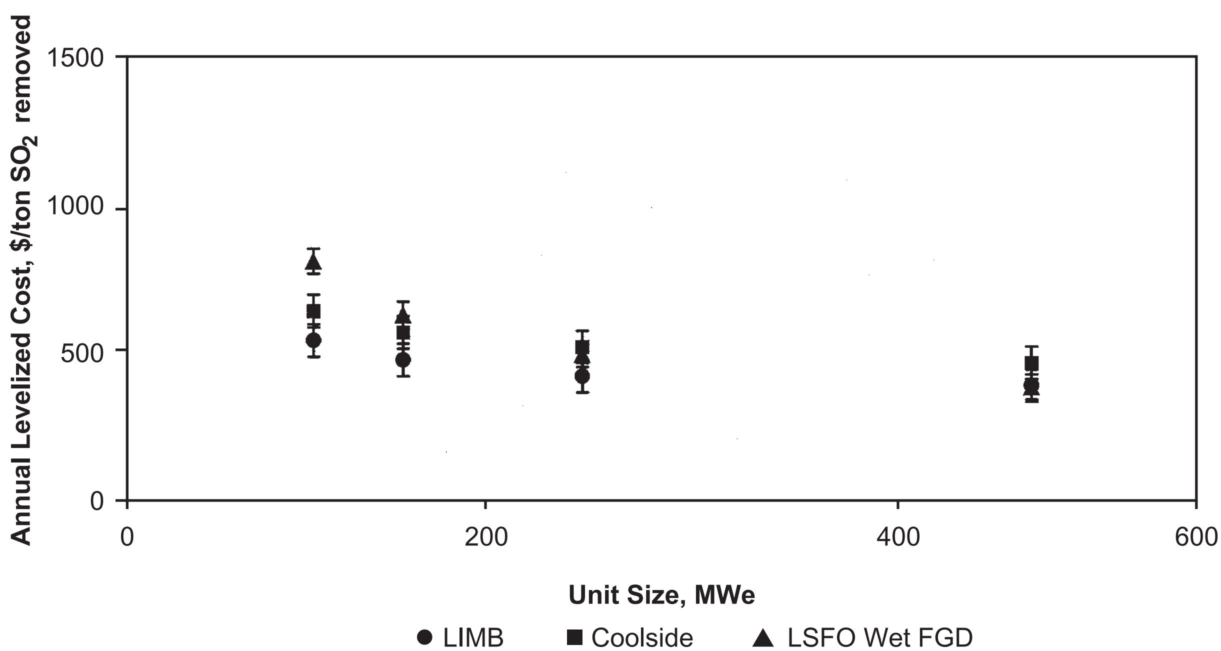

Figure 17 Annual levelized cost in the U.S.A. for 2.5% S coal.

have yet to be truly established for a large, commercial, industrial or utility application. The higher-than-expected removal efficiencies realized in the 5 MW_e demonstration are improving previous economic projections. Moreover, it is virtually impossible to break out the costs according to the individual pollutants. As a result, it is a bit premature to say more than to suggest that the capital and operating costs of the SNRB process are expected to be competitive with the combined cost of a system incorporating separate SCR, wet FGD, and particulate removal components.

Summary

The control of SO_2 emissions from fossil fuel-fired boilers has progressed dramatically over the past 25 years. Wet scrubbers, and especially those employing the LSFO and MEL technologies, have become the state-of-the-art methods for achieving removal efficiencies in the 90% to 98% range. (Spray) dry scrubbing with lime slurries for lower removal efficiency is seen as a technology more useful for lower sulfur coals. However, it may prove to be economically viable for some higher sulfur coal applications as well, especially when combined with sorbent

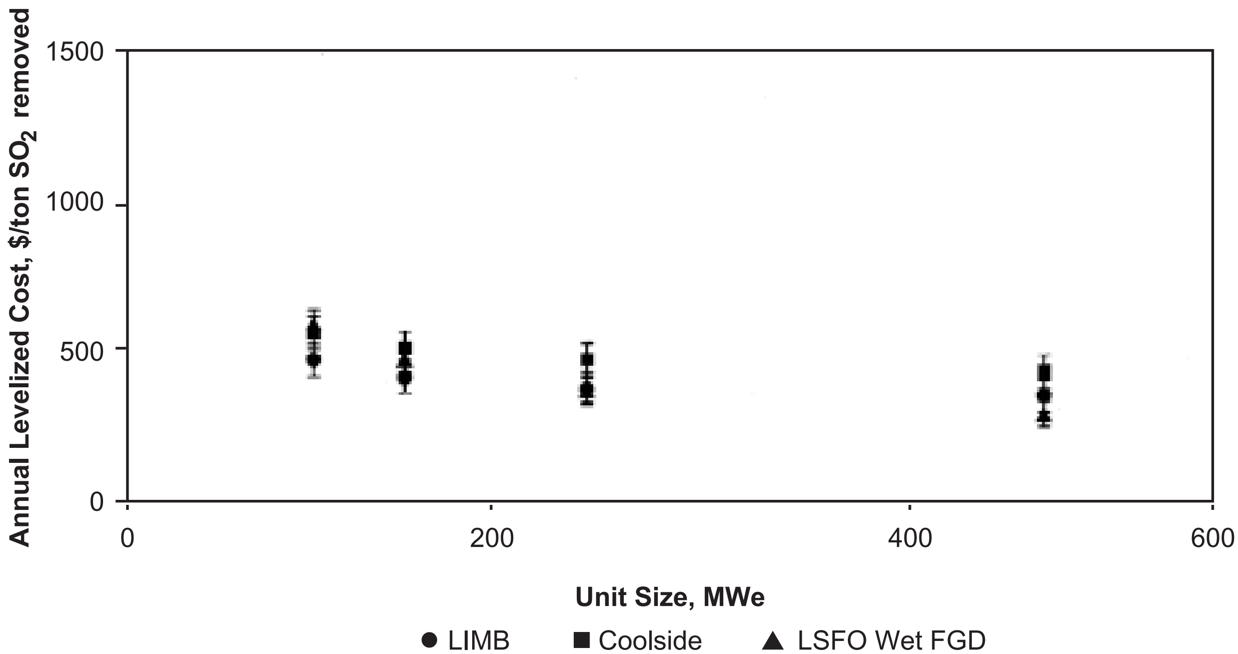

Figure 18 Annual levelized cost in the U.S.A. for 3.5% S coal.

injection as is done in LIDS. Interest in the sorbent injection technologies alone, for moderate levels of removal at relatively low capital cost, at first grew out of anticipation of the CAAA in the U.S., only to become technologies that may be of even more value worldwide. Finally, development of the advanced SNRB process, based on elements learned from the previous projects, continues to push the technologies into new areas that are expected to provide overall increased emissions control economically.

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