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**ALTERNATIVE FLUE GAS TREATMENT TECHNOLOGIES FOR
INTEGRATED SO₂ AND NO_x CONTROL**

**Joanna M. Markussen
U.S. Department of Energy
Pittsburgh Energy Technology Center
P.O. Box 10940
Pittsburgh, Pennsylvania 15236**

and

**C. David Livengood*
Argonne National Laboratory
9700 South Cass Avenue
Argonne, Illinois 60439**

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JOANNA M. MARKUSSEN
U.S. Department of Energy
Pittsburgh Energy Technology Center
P.O. Box 10940
Pittsburgh, Pennsylvania 15236

C. DAVID LIVENGOOD
Argonne National Laboratory
9700 South Cass Avenue
Argonne, Illinois 60439

ABSTRACT

Enactment of the 1990 Clean Air Act Amendments, as well as passage of legislation at the state level, has raised the prospect of more stringent nitrogen oxides (NO_x) emission regulations and has fueled research and development efforts on a number of technologies for the combined control of sulfur dioxide (SO₂) and NO_x. The integrated removal of both SO₂ and NO_x in a single system can offer significant advantages over the use of several separate processes, including such factors as reduced system complexity, better operability, and lower costs. This paper reviews the status of a number of integrated flue gas cleanup systems that have reached a significant stage of development, focusing on post-combustion processes that have been tested or are ready for testing at the pilot scale or larger. A brief process description, a summary of the development status and performance achieved to date, pending commercialization issues, and process economics (when available) are given for each technology.

INTRODUCTION

The development of advanced flue gas cleanup (FGC) technologies for the control of SO₂ and NO_x emissions continues to be a very active area of research and development, both in this country and abroad. This activity is driven both by legislation (such as the 1990 revisions to the federal Clean Air Act and state-level actions reflecting local concerns) and by the desire to develop technologies that surpass current options in terms of performance, costs, operability, and waste/by-product properties. New issues, such as concern over global climate changes and the health effects of toxic air emissions ("air toxics"), are also helping to shape and prioritize the development programs.

Commercially applied control technologies have typically involved combustion modification techniques for NO_x and some form of wet scrubbing for SO₂. Recently, both

selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) for NO_x control have achieved commercial status for some applications, spray-dryer technology has led to the development of a wet/dry scrubber system for SO₂ that produces an easily handled dry waste, and various duct injection processes have demonstrated moderate levels of SO₂ control. Ongoing development programs address a wide variety of alternative technologies that include a number of integrated processes for the removal of both SO₂ and NO_x in a single system. Such integration generally reduces system complexity and costs, enhances operability/reliability, and takes advantage of beneficial synergisms between pollutants in the removal process. In some cases, careful integration of the technology with other processes in the plant can yield additional benefits, such as significant energy savings.

This paper provides a status report on a number of integrated FGC systems that have reached a significant stage of development, focusing on post-combustion processes that have been tested or are ready for testing at the pilot scale or larger. Although a wide variety of technologies is discussed, there are a number of other integrated approaches that are not dealt with here, including options such as slagging combustors, fluidized-bed combustion, gasification/combined-cycle systems, and various processes involving the injection of sorbents or reactants solely into the furnace. These other approaches may offer features that should not be overlooked when evaluating alternatives for a specific application.

TECHNOLOGY SUMMARIES

In order to achieve mandated air quality objectives as rapidly as possible, it is clear that emissions control equipment will have to be installed at many existing facilities. Almost any technology can be installed as a retrofit, given sufficient resources, but the realities of plant layout, operating characteristics, and/or remaining service life can make such an installation exceedingly difficult and inordinately expensive. The first two technologies described in this section have been developed specifically for retrofit of NO_x control to existing flue gas desulfurization (FGD) systems, a particularly important consideration for the many facilities with existing scrubbers. The third technology, in-duct sorbent injection, is being developed as a low-cost retrofit of both SO₂ and NO_x control that avoids the installation of major equipment items. The remaining technologies are complete systems that are designed to remove both species (and perhaps particulate matter (PM) as well), but that also involve more

extensive new equipment requirements. Unless explicitly stated, the existence of an electrostatic precipitator (ESP) or baghouse for PM control is assumed in all cases. While the performance of the particulate control device is not emphasized here, its importance can be expected to increase in the future in connection with the capture of fine particulate matter that may be carrying toxic species.

Wet Scrubbing with Metal Chelates

The dominant FGD technology today is wet scrubbing based on limestone, lime, or sodium carbonate. All of these processes are capable of well over 90% SO₂ removal, but they are largely ineffective for NO_x removal due to the low solubility of the principal species, nitric oxide (NO). It has been found that some metal chelate additives, such as ferrous ethylenediaminetetraacetate (Fe(II)-EDTA), promote NO_x removal because they quickly remove any absorbed NO from solution and thereby maximize the absorption driving force. The coordinated NO can react with a sulfite ion, freeing the ferrous chelate for further reactions with NO. This synergism makes external regeneration of the Fe(II)-EDTA to release the NO unnecessary. Wastes contain the usual FGD products (e.g., CaSO₃/CaSO₄), together with nitrogen-sulfur compounds and perhaps other species.

A significant process problem is oxidation of the iron in the additive to the inactive ferric state. Research efforts have been directed at iron regeneration through "secondary" additives with antioxidant/reducing properties, reduction of ferric ions at elevated temperatures using sulfite/bisulfite ions in the scrubber liquor, and reduction using electrochemical cells.

Pilot-scale tests of the technology were conducted during 1991 by the Dravo Lime Company with support from the U.S. Department of Energy (DOE). The tests utilized a 1.5-MW pilot plant constructed by Dravo at the Miami Fort Station of the Cincinnati Gas and Electric Company. An antioxidant was used to maintain the desired ferrous ion concentration. Nitrogen oxides removals of up to 60% were obtained using packing in the scrubber tower. The corresponding SO₂ removals were essentially 100%. A thorough physical and chemical characterization of the waste conducted by Dravo Lime and Argonne National Laboratory (ANL) did not reveal any problems for disposal, and biological tests have shown that even the unstabilized material is of very low toxicity. Stabilization has been readily achieved using conventional methods. Further pilot-scale tests of the technology are planned by Dravo Lime beginning in the spring of 1995.

An economic analysis of the technology has been conducted by the Dravo Lime Company. Using 1990 FGD

costs from the Electric Power Research Institute (EPRI), assuming installation of low-NO_x burners for 50% NO_x reduction, an additional 50% reduction from the metal-chelate-enhanced scrubbing, and maintenance of the ferrous ion concentration using each of the methods noted above, Dravo found capital costs for adding NO_x control of \$74-96/kW (depending upon design and operating conditions) and levelized operating costs of \$948-1097/ton NO_x removed.

Modified Spray Dryer Scrubbing

Spray dryer FGD technology is based on the spray drying of an alkali sorbent, typically lime slurry, followed by collection of the resulting dry particulate. The slurry is atomized and mixed with hot flue gas, which evaporates virtually all of the water while SO₂ is simultaneously absorbed and reacted with the alkali. The resulting dry powder and fly ash are collected in either a baghouse or an ESP and sent to a landfill for disposal. Process simplicity, low energy and water consumption, and the dry state of the waste are significant advantages. Sulfur dioxide removals of up to 90% have been demonstrated in both low- and high-sulfur applications.

Very little NO_x is removed under normal operating conditions, but research at the Pittsburgh Energy Technology Center (PETC) showed that elevated spray dryer exit temperatures and the addition of sodium hydroxide (NaOH) to the lime can promote significant NO_x removal. Full-scale (20-MW) demonstration of this technology was carried out in two series of tests at ANL using flue gas from the firing of high-sulfur (3.5%) coal. Raising the spray dryer exit temperature from the normal value of about 65°C to above 82°C initiates NO_x removal, which is accompanied by some net nitrogen dioxide (NO₂) increase in the stack gas, ranging from 6-18 ppm. The addition of NaOH at 2.5-10% by weight of lime improves NO_x removals and reduces the lime requirement for SO₂ control. Most of the NO_x removal occurs in the baghouse, and extended intervals between bag cleanings produce the best performance, with average values of about 35% being attained at ANL. With some operating modifications, NO_x removals up to 50% should be attainable. Removals also depend strongly on the SO₂/NO_x ratio, being higher for high SO₂ concentrations in the flue gas. It should be noted, however, that the temperatures needed to promote NO_x removal also tend to suppress SO₂ capture, making it difficult to simultaneously optimize both NO_x and SO₂ control.

Detailed costs for the process are not available, but one preliminary estimate projected operating costs about 20% higher than those for normal SO₂ scrubbing. Process uncertainties are related to waste characteristics (solubility

of sodium compounds) and long-term steady-state performance. Note that this retrofit technology represents a fully integrated $\text{SO}_2/\text{NO}_x/\text{PM}$ process.

In-Duct Sorbent Injection

Several processes use in-duct injection of sorbents to achieve combined SO_2/NO_x control or to supplement other removal measures. Research-Cottrell Environmental Services and Riley Stoker tested one of these processes, the Integrated Dry Injection Process, in a 5,000-scfm proof-of-concept unit at the Riley Stoker Research Facility. The process uses low- NO_x burners, dry injection of alcohol-water hydrated lime at economizer temperatures for primary SO_2 capture, dry injection of commercial-grade sodium bicarbonate at the air heater exit for additional SO_2 and NO_x removal, and evaporative cooling for precipitator conditioning. The injection of high surface area alcohol-water hydrate at a Ca/S ratio of 2 resulted in 55-60% SO_2 removal. Sodium bicarbonate injection at a Na_2/S ratio of 1 increased the system SO_2 removal to 90%. Assuming 50% NO_x reduction from the low- NO_x burner, the sodium bicarbonate increased the system NO_x removal to 65%. An economic analysis limited to the installation of low- NO_x burners and a hydrated lime injection system on a 300-MW plant providing 60% SO_2 removal and 50% NO_x removal estimated process capital costs of \$94/kW and a first year operating cost of \$560/ton of $\text{SO}_2 + \text{NO}_x$ removed.

Another process, which was selected for testing under the third round of the DOE Clean Coal Technology Program, is being developed by a team led by the Public Service Co. of Colorado. A 100-MWe demonstration at Arapahoe Power Station's Unit 4 top-fired boiler combines low- NO_x burners, overfire air, and SNCR for NO_x control and dry injection of either calcium- or sodium-based sorbents with humidification for SO_2 control. A baghouse is used for PM control and provides a site for additional SO_2 removal. Testing began in August 1992 and will be completed in the summer of 1995 with long-term performance testing of the integrated process. Total NO_x reduction with low- NO_x burners and overfire air ranges from 63 to 69% with no increase in unburned carbon or CO emissions. Adding urea injection increases the total NO_x removal to greater than 80% with an ammonia (NH_3) slip of 10 ppm or less. Nitrous oxide (N_2O) generation is a potential concern with urea injection but is greatly reduced with the injection of ammonia compounds converted from urea. When burning low-sulfur coal, SO_2 removal with duct injection of calcium-based sorbents is 40% or less, but with sodium-based sorbents, it is near 70% at a stoichiometric ratio around 1.0. However, an increase of NO_2 emissions is observed with the use of sodium compounds. Fortunately, the integration of the urea-based SNCR and sodium-based

dry sorbent injection appears to reduce the net stack NH_3 and NO_2 emissions.

Dry sodium bicarbonate injection has also been tested at five coal-fired utility boilers by NaTec Resources, Inc., and has been commercially installed at several industrial sites. Removal values have been as high as 75% for SO_2 and have ranged from 0-40% for NO_x on systems equipped with ESPs. Sulfur dioxide removals as high as 90%, with 25% NO_x removal, were obtained in small-scale tests with injection upstream of a baghouse. Solubility of the wastes requires a lined pond with a leachate collection system for disposal. To enhance the attractiveness of the process, recent development efforts have been focused on recovery of sodium sulfate (Na_2SO_4), a commercially valuable by-product. However, full-scale tests have yet to be conducted for a complete scrubbing/by-product system. Projected costs reported by the developer in 1990 for such a system were \$81/kW capital cost (including a new baghouse) and 5.05 mills/kWh leveled cost.

NOXSO Process

The NOXSO process is a dry, regenerable FGC system designed to simultaneously remove over 90% of the SO_2 and 70-90% of the NO_x from flue gas. The gas is cleaned as it passes through a fluidized bed of sodium-impregnated alumina sorbent at about 120°C. Removal of PM can be accomplished either before or after the process.

Regeneration of the sorbent is performed separately for NO_x and SO_2 . Adsorbed NO_x is released as the sorbent is heated to about 620°C with hot air in a second fluidized bed. The off-gas can be recycled to the combustor with the combustion air. As a result of chemical equilibria in the combustor, NO_x formation is suppressed, resulting in a new, slightly higher, steady-state NO_x concentration in the flue gas. Thus, the only NO_x by-product is nitrogen (N_2). After heating, the sorbent is treated with a reducing gas, such as methane, and steam to produce a concentrated stream of SO_2 and hydrogen sulfide (H_2S). These species are converted in a Claus reactor to elemental sulfur, which is sold as a by-product.

Small-scale process tests have been conducted at the Tennessee Valley Authority's Shawnee Plant and at PETC. Proof-of-concept testing has been completed in a 5-MWe pilot plant at Ohio Edison's Toronto Plant. A 150-MW demonstration of the process at ALCOA's Warrick Plant is anticipated under the third round of the DOE Clean Coal Technology Program. During pilot-plant tests, removal efficiencies averaged 95% for SO_2 and 80% for NO_x . Various optimization studies were performed resulting in increased absorber removals, selection of future construction materials, development of a lower density

sorbent with increased crush strength, modifications in the sorbent transport system, and reduction in the process sorbent inventory. The efficiency of NO_x reduction through recycle to the combustor has yet to be tested at a large scale. An economic analysis estimated capital costs for the process at \$247/kW (1993 dollars) with leveled costs of 7.1 mills/kWh including sulfur plant revenues.

SNRB Process

The SNRB™ (SO_x-NO_x-Rox Box™) process of Babcock & Wilcox combines injection of an SO₂ sorbent with a hot catalytic baghouse for NO_x and PM removal. A calcium- or sodium-based sorbent is injected downstream of the boiler economizer and reacts with SO₂ in both the duct and the filter cake on the bags. Ammonia injected into the flue gas reacts with NO_x over a catalyst suspended within the filter bags, producing N₂ and water. A key process feature is the use of woven ceramic fiber filter bags to withstand temperatures of 425-470°C. Low exit SO₂ and sulfur trioxide (SO₃) levels may permit lower air preheater exit temperatures and greater system thermal efficiency.

A 5-MWe process demonstration was completed in May 1993 at Ohio Edison's R.E. Burger Plant under the second round of the DOE Clean Coal Technology Program. During the one-year demonstration program, SO₂ removal efficiencies greater than 80% were achieved using commercial hydrated lime at Ca/S stoichiometries of 1.8-2.0. Testing with sodium bicarbonate showed that SO₂ removals over 90% were attainable at a normalized stoichiometry (Na₂S) of 2.0 over a wide range of baghouse temperatures from 220-470°C. Nitrogen oxides reductions of greater than 90% were achieved at NH₃/NO_x molar ratios of 0.85-0.9. A minimum lifetime of 3 yr is currently being projected for the NO_x catalyst. An economic study developed using EPRI guidelines estimates process capital costs of \$240/kW and an annual leveled cost of \$509/ton SO₂ + NO_x removed for a 500 MW plant burning 2.5 wt. % S coal (1993 dollars, assuming a 15 yr book life).

SNOX™ and DESONOX Processes

The SNOX™ process, developed by Haldor Topsøe A/S, is designed to catalytically remove 95% or more of both the SO₂ and NO_x in the flue gas while producing a salable by-product of concentrated sulfuric acid. Selective catalytic reduction of NO_x to N₂ and water using NH₃ is followed by catalytic oxidation of SO₂ to SO₃. The SO₃ is hydrated to sulfuric acid, which is then concentrated to >93 wt. % acid strength in an air-cooled falling-film condenser constructed of borosilicate glass tubes. Although the process consumes a significant amount of energy, extensive energy recovery within the process is claimed to give net energy savings for the plant of 1-4% (1% for each percent of sulfur in the

fuel), due mainly to the exothermic heat of formation of sulfuric acid. Ammonia slip from the SCR reactor is oxidized in the SO₂ converter and does not present an emissions problem. A baghouse or ESP upstream of the SCR unit removes most PM. Any remaining fine particulates are retained in the SO₂ converter catalyst bed, which undergoes periodic cleaning by means of a semi-automatic system for sifting the catalyst. Lifetimes of 7-10 yr for the SO₂ catalyst and 3-6 yr for the NO_x catalyst are currently projected.

In Denmark, a 3-MW process demonstration unit operated on a low-sulfur flue gas stream from 1987 until 1991, and a 305-MW full-scale SNOX™ plant was commissioned in November 1991 on a boiler firing various coals containing 0.5 to 3% sulfur. Removals of 95% SO₂ and 95% NO_x have been achieved. A 30-MW unit has been in operation on a petroleum-coke (6% sulfur)-fired boiler in Italy since April 1991. That unit has maintained greater than 96% NO_x removal and over 96% SO₂ removal. In the United States, a 35-MWe demonstration of the technology was conducted at Ohio Edison's Niles Station under the second round of the DOE Clean Coal Technology Program. The process is licensed to Asea Brown Boveri (ABB) Environmental Systems, who performed the U.S. test program which was completed in December 1994. At the conclusion of the test program, Ohio Edison assumed ownership of the unit and is continuing to operate the process. Sulfur dioxide removal has typically been over 95% and NO_x removal efficiencies have averaged 94%. The sulfuric acid product concentration has been consistently 93-94 wt. % and has met acid color and clarity requirements for a Class 1 acid. All of the acid product has been either sold for industrial use or used on-site in the boiler water demineralizer systems. A recent study estimated process capital costs of \$235/kW (1995 dollars) and first year total operating costs of 5.5 mills/kWh.

A similar process called DESONOX was conceived by the German firm Degussa and is being developed jointly with Stadtwerke Münster, Lentjes, and Lurgi. A single reactor tower containing both reduction and oxidation catalysts is used. The sulfuric acid by-product is claimed to be of sufficient purity to be used in producing fertilizers. The process has been demonstrated on a 98-MW boiler at the Hafen cogeneration plant in Münster since November 1988; a second unit was to be operational at the same facility in the summer of 1992. Removals for low-sulfur coal operation have been approximately 80% for NO_x and 94% for SO₂.

Copper Oxide Process

The copper oxide (CuO) process combines SO₂ capture with catalytic reduction of NO_x using NH₃ in an absorber

containing CuO-impregnated alumina sorbent. Regeneration of the sorbent using a reducing gas produces a concentrated SO₂ stream that can be processed into a salable by-product. In the 1970s, Shell developed a parallel passage (fixed-bed) reactor system and conducted full-scale tests on an oil-fired boiler at the Showa Yokkaichi Sekiyu refinery in Japan. In the U.S., UOP licensed the Shell process and completed pilot-plant tests (0.5 MWe) on a coal-fired unit at Tampa Electric Company's Big Bend Station in 1980. Average removals of 90% for SO₂ and 70% for NO_x were documented, although with design modifications, 90% NO_x reduction was projected.

Concurrent with Shell's work, PETC independently developed a fluidized-bed reactor system. Small-scale tests of the Fluidized-Bed Copper Oxide process have yielded approximately 90% removal of both SO₂ and NO_x. Under DOE contract, UOP has drafted a conceptual design and economic evaluation of a 500-MW commercial-scale unit. A study conducted in 1991 estimated total capital costs of \$228/kW (1990 dollars), with levelized operating costs of 19.97 mills/kWh. Reduced operating costs have been projected for a moving-bed absorber variation of the process, which was tested at the laboratory scale by Rockwell International Corp. The Moving-Bed Copper Oxide process is currently being tested in a pilot unit at PETC.

E-Beam Process

Irradiation of flue gas with high-energy electrons initiates chemical reactions that oxidize SO₂ to SO₃ and NO to NO₂, which can be further reacted with a suitable base to form solid salts. An E-beam process being developed by Ebara demonstrated removals of over 90% and 80% for SO₂ and NO_x, respectively, in a 5-MW pilot plant. Using NH₃ as a base, an ammonium-sulfate/ammonium-nitrate by-product with potential value as an agricultural fertilizer was produced. A similar process developed by Research-Cottrell using lime rather than NH₃ as the base achieved removals of 90% for SO₂ and 60% for NO_x in pilot-scale tests. Ebara is currently investigating the concept of zone irradiation to achieve high efficiencies at lower total dose rates. It is hoped that this will reduce the process energy use by about one-third, to no more than 2% of the plant's gross output. Other commercialization issues include uncertainties regarding by-product utilization and economic scaleup of the electron-beam guns. One study put process capital cost at about \$400/kW (1990 dollars) and levelized costs at about 13 mills/kWh, although both values could be significantly reduced with successful development of the zone-irradiation concept and favorable by-product economics.

Activated Coke Process

Activated coke can both adsorb SO₂ and catalyze the reduction of NO_x by ammonia. The use of two sorbent beds allows optimization of removal for each species. Regeneration of the spent sorbent at high temperature produces a concentrated SO₂ stream that can be further processed to yield a salable by-product, such as sulfuric acid or elemental sulfur. Such systems have been applied commercially by Bergbau-Forschung GmbH (now Deutsche Montan Technologies) and others in Japan and Germany, where SO₂ removals of 90-99.9% and NO_x removals of 50-80+% have been reported. However, most experience has been with low- to medium-sulfur systems, and there is some question regarding process suitability for high-sulfur systems because of high coke consumption. General Electric Environmental Services, Inc. has licensed the Mitsui-BF process for applications in North America. A potential advantage to the activated coke process is the removal of selected air toxics. Capital costs of \$220-240/kW have been projected for a 500-MW system in the United States firing medium-sulfur coal; no operating costs were reported.

Recently, the Electric Power Development Co. Ltd. of Japan has been investigating a single moving-bed activated char process for application to NO_x removal and SO₂ removal "polishing" on a fluidized-bed combustion system. Pilot-scale tests have given removals of over 80% for NO_x and 90% for SO₂. Development issues appear to include the char loss rate, start-up temperature response of the char bed, and negative effects of high moisture and SO₂ levels on NO_x removal.

Parsons Process

Very high levels of SO₂ and NO_x removal (up to 99%) are the objective of the Parsons Process. Simultaneous catalytic reduction of SO₂ to H₂S and NO_x to N₂ occurs in a hydrogenation reactor using steam-methane reformer gas. The resulting H₂S is recovered and processed to produce elemental sulfur, a marketable by-product, through the combination of two commercial technologies (FLEXSORB and Recycle Selectox). The performance of the catalytic hydrogenation reactor has been tested with high-sulfur coal in a pilot plant at the St. Marys Municipal Power Plant in Ohio. Results showed that SO₂ reduction of 98+% and NO_x reduction of 92-96% were achievable. Although the long-term performance of the catalyst in a particulate-laden gas stream is unknown, a two-day test with high dust loading in the flue gas showed no change in the performance of the catalytic SO₂ and NO_x removals and no plugging of the honeycomb catalyst openings. On the basis of EPRI economic procedures, projected capital costs for a 500-MW plant are \$285/kW (1982 dollars) and levelized

busbar costs are about 26 mills/kWh. A significant process development issue may be the effect of flue gas O₂ content on increasing hydrogen consumption and, hence, operating costs.

Other NO_x/SO₂ Control Technologies

Other NO_x/SO₂ control technologies undergoing development, but for which limited information is available, are described below.

The SOXAL™ process is a regenerable sodium-based scrubbing system coupled with urea/methanol injection in the boiler with the goal of 90% SO₂ and NO_x removal. A sodium sulfite scrubbing solution absorbs SO₂ and is regenerated by an electrochemical process using bipolar membranes. Urea reduces 50-70% of the NO to N₂, and methanol oxidizes the remaining NO to NO₂, which is then removed in the sodium sulfite scrubber. A 3-MW pilot program was completed in July 1993 by AlliedSignal, Inc. at the Niagara Mohawk Power Corporation's Dunkirk Station. Removals of 98% SO₂ and up to 70% NO_x were observed. However, high oxidation of the sodium sulfite solution to sodium sulfate occurred during the simultaneous SO₂/NO_x scrubbing mode. As of December 1994, the Graver Company's AQUALYTICS Division has acquired the SOXAL™ technology and is marketing it commercially, mainly as an SO₂ removal process.

The MagSorbent process, being developed by Sorbent Technologies Corporation, uses magnesia-coated expanded-vermiculite granules for 90% SO₂ removal and moderate levels (30-40%) of NO_x removal. The flue gas is humidified to within a 30°C approach to the adiabatic saturation temperature upstream of a radial panel-bed filter containing the dry magnesia (MgO). The sorbent is regenerated at 600°C with air or a reducing gas. A 2.5-MW pilot plant was operated in a batch mode at Ohio Edison's Edgewater Station. Testing was completed in May 1993 and demonstrated 90% SO₂ removal efficiencies and 20+% NO_x reductions. A 10-MWe demonstration unit has been proposed for a European site.

The LILAC (Lively Intensified Lime-Ash Compound) process is being developed by Hokkaido Electric Power Co., Inc. (HEPCO) and Mitsubishi Heavy Industries Ltd., both of Japan. The process uses a sorbent that is produced by mixing fly ash, lime, and gypsum with hot water at 95°C for 15 min. Depending upon the Ca content, the sorbent may or may not undergo an aging process for 12 hours. In the SO₂/NO_x removal process, the sorbent is dried to a powder and injected into the flue gas duct. The solids are collected in either a downstream baghouse or ESP. Pilot-plant testing of the duct injection LILAC system began in April 1993 at the HEPCO Tomato-atsuma

Power Station. Removals of 75% for SO₂ and 55% for NO_x were obtained at a Ca/S molar ratio of 2.9. Development of the process is continuing, with efforts directed at increased system reliability and economic competitiveness.

A Lurgi dry FGD process using a circulating fluidized-bed reactor has been in commercial operation on five coal-fired utility boilers in Germany since 1987, and a combined NO_x/SO₂ version of the process is currently under development. It uses a hydrated lime sorbent for SO₂ capture and an unsupported FeSO₄ catalyst plus NH₃ for reducing NO_x. Typical operating temperatures are on the order of 385°C, requiring placement of the absorber upstream of the air preheater. Pilot-plant tests on a low-sulfur system (inlet SO₂ concentrations of 450-630 ppm) gave SO₂ removals up to 97% for Ca/S mole ratios of 1.6-1.8. Removals of NO_x up to 88% were achieved with an NH₃/NO mole ratio of 0.7. High sorbent recycle rates (up to 98%) are used in the large-scale FGD systems, but no data were reported for catalyst recycle or loss rates in the pilot plant.

SUMMARY

There is an increasing probability that flue gas cleanup for NO_x removal will be required at some installations in the United States. If that is the case, integrated systems that combine control functions in a single process offer a number of advantages for both retrofit and new situations. In recent years, considerable progress has been made in developing and characterizing a number of such systems, and new concepts continue to emerge from the laboratory.

The variety of concepts under development provides many technical and economic options to system designers:

- Retrofit versus totally new systems
- Tradeoffs between cost and removal capabilities
- Tradeoffs between SO₂ and NO_x removals
- Salable by-products versus throwaway waste

The spectrum of possibilities is certainly challenging to those who must sort through and evaluate the options on the way to a multi-million dollar technology selection. On the other hand, this same spectrum will make it possible to tailor an optimal energy/environmental system for the unique site and business characteristics of any particular installation.

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