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PITTSBURGH ENERGY TECHNOLOGY CENTER

THE REMOVAL OF SO_2 USING GAS SUSPENSION ABSORPTION TECHNOLOGY DEMONSTRATION PROJECT

A DOE ASSESSMENT

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EXECUTIVE SUMMARY

This document serves as a DOE post-project assessment of a project in Round 3 of the Clean Coal Technology (CCT) Demonstration Program titled, "Demonstration of SO_2 Removal Using Gas Suspension Absorption Technology." In October 1990, AirPol Inc. entered into a cooperative agreement to conduct the study, with the Tennessee Valley Authority (TVA) as the host and co-sponsor. The 10 MWe plant scale demonstration was conducted from November 1992 to March 1994 at TVA's National Center for Emissions Research (NCER), located at the Shawnee Fossil Power Plant near Paducah, KY,

The major objectives of the GSA demonstration were successfully achieved:

- The process removed over 90% of the SO_2 in the flue gas with a low level of time consumption.

- The process operated reliably. The GSA system is comprised of simple carbon steel (corrosion-free) components, can achieve high SO_2 removal efficiencies with a low level of lime consumption for a range of coal sulfur contents, has low maintenance requirements, does not require a dedicated operator, and has demonstrated an availability of virtually 100 percent.

- Particulate emissions were well below the New Source Performance Standards. Substantially all of the hydrogen chloride and hydrogen fluoride in the flue gas were absorbed in the GSA reactor. A high percentage of trace metals reporting to the gas stream also were removed by the system.

The economics of the GSA process are favorable compared with conventional flue gas desulfurization using wet limestone. The capital cost for a GSA system is about 30% less, and the levelized annual costs for many applications are substantially lower.

No problems were experienced with boiler operation or other emissions. The demonstration project produced valuable data for application to larger scale projects, and commercialization activities have begun.

The GSA process is a promising technology that will aid U.S. utilities and other industries in achieving an effective, economic, and space-efficient solution to the SO_2 emissions problem. The Ohio Coal Development Office has awarded the city of Hamilton a grant to install GSA technology in the city's municipal power plant. This will allow Hamilton to meet environmental regulations while using high-sulfur Ohio coal for power generation.

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I. Introduction

The goal of the U.S. Department of Energy (DOE) Clean Coal Technology (CCT) program is to furnish the energy marketplace with a number of advanced, more efficient, and environmentally responsive coal utilization technologies through demonstration projects. These projects seek to establish the commercial feasibility of the most promising advanced coal technologies that have proceeded beyond the proof-of-concept stage of development.

This document serves as the DOE post-project assessment of a project in CCT Round 3 titled "Demonstration of SO_2 Removal Using Gas Suspension Absorption." The Post- Project Assessment Report is an independent DOE appraisal of the success a completed project has had in achieving its objectives and aiding in the commercialization of the demonstrated technology. The Report also provides an assessment of the expected technical, environmental, and economic performance of the commercial version of the technology, as well as an analysis of the commercial market.

In October 1990, AirPol Inc. entered into a cooperative agreement to conduct the study. The host site was the National Center for Emissions Research (NCER), located at the Shawnee Fossil Power Plant near Paducah, KY, and operated by the Tennessee Valley Authority (TVA). The equivalent capacity of the slipstream from the boiler used in the test program was 10 MWe. The demonstration was conducted over a 17-month period from November 1992 through March 1994. The independent evaluation contained herein is based primarily on information from the Final Project Report prepared by AirPol [I] as well as other references.

Gas Suspension Absorption (GSA) is an innovative technique for removing sulfur dioxide (SO_2) from flue gases. It has the potential to provide a more economical approach to flue gas desulfurization (FGD) than conventional processes now in widespread use.

The major performance objectives of this project were to:

- Achieve SO_2 removal in excess of 90% when firing high-sulfur U.S. bituminous coal.
- Maintain particulate emissions below the New Source Performance Standards (NSPS), 12.9 g/GJ (0.03 lb/10^6 Btu).
- Demonstrate reliable long-term operation.

All three of these objectives were successfully achieved, and the GSA process is being commercialized in the U.S. and elsewhere.

II. Technical and Environmental Assessment

A. Promise of the Technology

Combustion of coal results in the generation of flue gas containing SO_2. Many U.S. coals have a sufficiently high sulfur content to cause SO_2 emissions to exceed environmental standards. Thus, unless a compliance (low-sulfur) coal is used and absent any precombustion treatment, some form of postcombustion FGD treatment is generally required. This is most commonly achieved by reacting the SO_2 with a sorbent such as lime or limestone.

Sorbent based FGD processes can be categorized as wet, semi-dry, or dry systems. In wet FGD systems, flue gas is contacted with an aqueous solution or slurry containing a sorbent, usually in a separate absorption tower or vessel. Contact with the aqueous stream cools the flue gas to the adiabatic saturation temperature and the SO_2 is removed from the flue gas. The by-product is a slurry, which must be dewatered for disposal.

Dry FGD systems generally involve injecting dry sorbent into the furnace or flue gas duct; the by-product solids are collected with the fly ash from the boiler. An advantage of dry systems is the relative ease of waste disposal. In semidry FGD systems, the sorbent is introduced as an aqueous slurry, but the water content is controlled so that the slurry dries completely in the flue gas ductwork and the by-products are dry solids. The flue gas remains above the adiabatic saturation temperature.

Several FGD systems are in commercial use. Wet limestone processes provide high SO_2 removal efficiency, generally 90% or greater. Dry or semi-dry FGD processes involving spray drying or sorbent injection generally exhibit a lower level Of SO_2 removal, generally 50%, but some as high as 70%, because of reduced mass transfer efficiency between the flue gas and the sorbent.

With the increased emphasis on SO_2 emissions reduction by electric utility and industrial plants as required by the Clean Air Act Amendments of 1990 (CAAA), there is a need for a simple and economical dry or semi-dry FGD process to compete with wet scrubbing. In response to Round 3 of the CCT solicitations sponsored by the U.S. DOE, AirPol Inc. proposed demonstration of one such technology, namely the GSA process. AirPol, with U.S. headquarters in Teterboro, NJ, performed the demonstration at a 10 MWe unit operated by the Tennessee Valley Authority (TVA), under a Cooperative Agreement awarded by DOE in October 1990.

B. Process Description

Overview

Gas suspension absorption (GSA) is an innovative semi-dry FGD technology which uses lime sorbent to react with SO_2. The major by-products are solids: dry calcium sulfite and calcium sulfate. The overall chemical reactions are given by the following equations:

$$SO_2 + CaO + \_H_2O \rightarrow CaSO_3\ \beta\_H_2O$$

$$SO_2 + CaO + 2\ H_2O + \_O_2 \rightarrow CaSO_4\beta 2H_2O$$

A more detailed process description is given in a subsequent section.

History of the GSA Process

To understand the application of the GSA process in FGD service, it is helpful to review its history. The GSA concept was developed by AirPol's parent company, FLS miljo, a wholly-owned subsidiary of FLS Industries of Copenhagen, Denmark. The process was initially used in cement kiln operation, where it serves as a preheater for the drying step. GSA provides both capital and energy savings by reducing the required length of the rotary kiln and lowering fuel consumption.

Subsequently, the GSA concept was applied to the calcination of limestone, alumina, and dolomite. It has also been used successfully to clean flue gases from commercial waste-to-energy plants in Denmark, primarily for the capture of hydrogen chloride (HCI) emissions. The GSA system is distinguished in the European municipal solid waste (MSW) market by its low capital and operating costs.

In 1985, FLS miljo built a GSA system pilot plant at the Stignaes power station in Denmark to establish design parameters for absorption Of SO_2 from flue gas. However, the power station subsequently managed to meet the emissions code for SO_2 without using FGD and, thus, had no further interest in installing a GSA system.

At the same time, the emissions regulations for SO_2 and HCI from MSW incinerators were tightened, and the GSA pilot plant was moved to an incinerator site. The first commercial GSA system was installed at the KARA waste-to-energy plant at Roskilde, Denmark, in 1988.

The GSA Technology in FGD Service

A process flowsheet is shown in Figure 1. Sorbent slurry is prepared by adding water to slaked lime, which is made by hydration of pebble lime, a form of quicklime, in a slurry tank. The fresh sorbent slurry is pumped to a single, dual-fluid spray nozzle located at the bottom of the reactor and atomized by compressed air, creating a circulating fluidized bed of solids containing lime.

The slurry droplets impact and coat the dry solids in the bed, thereby preventing slurry from hitting the wall of the reactor and causing a buildup of solids. Flue gas from the boiler enters the bottom of the reactor, where it contacts the suspension of solids coated with sorbent. The moisture in the slurry evaporates, while SO_2 reacts with the lime.

The solids are suspended in the reactor by the upward flow of the flue gas stream. The resulting turbulence provides intimate contact, allowing SO_2 to be absorbed into the thin layer of lime coating the solid particles.

The partially cleaned flue gas, containing suspended particles, continues to the cyclone, where most of the solids, consisting of calcium salts, fly ash, and unreacted lime, are removed. About I% of the solids are entrained in the flue gas exiting the cyclone, while the solids separated in the cyclone are recycled to the reactor via a feeder box.

Recycling solids to the reactor serves several purposes. First, it provides a large surface area for adsorption of the lime slurry, thus enhancing contact between the slurry and the flue gas. Second, recycling provides further opportunity for unreacted lime to react with SO_2, thereby increasing calcium utilization. Finally, the recycled solids provide a scouring action on the reactor walls, thus minimizing scaling.

The flue gas proceeds to a dust collector for final particulate removal. The dust collector can be either an electrostatic precipitator (ESP) or a fabric filter. The cleaned flue gas is released to the atmosphere via the stack.

The solids recovered in the dust collector, consisting of by-product salts and boiler fly ash, are sent to disposal. These solids have low leachability (as demonstrated by EPA tests), permitting safe disposal as landfill. Converting the by-product to a marketable material has also been considered. One possibility is to make a pozzolanic cement, which is a ready-mix product that can be used for non-structural concrete applications such as sub-base for roadways. Properties of concrete made from pozzolanic cement are quite similar to those of concrete made from Portland cement.

GSA System Controls

The GSA process is instrumented to automatically maintain the desired level of SO_2 removal while minimizing lime consumption. The system is comprised of three control loops, as shown in Figure 2.

1. Material Recycle A sensor in the reactor inlet measures the dynamic pressure and converts it to gas velocity (flow). A controller adjusts the speed of the metering screws in the feeder box, thereby controlling the flow of recycle material to the reactor.

2. Flue Gas Temperature A temperature sensor, located between the cyclone and dust collector, controls the speed of the pump directing water to the spray nozzle.

3. Emissions An SO_2 emissions monitor in the stack controls the speed of the pump injecting lime slurry into the reactor.

The metering screws in the feeder box, the cooling water pump, and the lime slurry pump are all driven by electric motors having variable frequency drives for precise speed control. The pumps are positive displacement pumps, which maintain constant pressure regardless of flow rate. This is beneficial for effective operation of the spray nozzle.

For more precise and faster response of the SO_2 emissions control system, especially when there are large and rapid fluctuations in the SO_2 concentration in the flue gas, an additional acid gas sensor is installed in the reactor inlet. This permits on-line calculation of the SO_2 removal efficiency, which in turn is used to control the lime slurry injection rate.

Comparison with Conventional Spray Dryer Systems

Because of its basic simplicity, the GSA process offers low capital and operating costs. Other dry or semidry FGD technologies require either a high speed rotary atomizer or high pressure atomizing nozzles, with multiple nozzle heads provided to ensure fine atomization and full coverage of the reactor cross section. By way of contrast, GSA uses a single, low pressure, dual-fluid nozzle with no moving parts. GSA's enhanced SO_2 removal ability stems primarily from the superior mass- and heat-transfer characteristics associated with the large wetted surface area of suspended solids. Since no moving parts are required, fabrication and installation are relatively simple and inexpensive.

A key feature of the GSA process is the recirculation of large amounts of dry solids, which are coated with lime slurry in the reactor and provide the surface on which the reaction takes place. The resulting heat- and mass-transfer characteristics of the system are superior to those in other dry or semi-dry FGD processes where sorbent is sprayed directly into a duct or spray dryer.

The GSA reactor/cyclone- operates at a high flue gas velocity (20-25 ft/sec), compared with 4-6 ft/sec for conventional spray dryers in FGD service. The residence time of the flue gas in the GSA absorber is only about 3 seconds as opposed to 10- 12 seconds in conventional spray dryers. As a result, the GSA reactor is only one-third to one-fourth the size of a spray dryer, which results in a lower equipment cost. The compact design of the GSA system also contributes to lower installation costs.

Power requirements in the GSA process are mainly for the induced draft fan and the compressor used for atomization of the lime slurry. The more significant of these is the fan, which is required to overcome the flue gas pressure drop across the absorber. Although the pressure drop in the GSA system is somewhat higher than in a conventional spray dryer system, the total power consumption for GSA is lower because the power for atomization is less than that for either rotary atomizers or atomizing nozzles used in spray dryer systems.

SO_2 removal occurs when the SO_2 in the flue gas dissolves in the water on the solid particles and reacts with lime. Very little reaction occurs with dry particles. To maximize SO_2 removal efficiency, two factors are important: 1) contact area between the particles and the flue gas, and 2) contact time before the particle becomes dry. Both of these factors are enhanced by maximizing the rate of water injection into the flue gas. A higher water injection rate for a given lime rate means a more dilute slurry and, thus, the ability to coat a large number of particles. Also, it will require more time to evaporate more water, thus providing a longer contact time in the highly reactive state.

However, as more water is injected, the flue gas temperature will more closely approach the adiabatic saturation temperature. If too much water is injected, the particles will not dry completely, resulting in buildup of solids and corrosion of equipment. The more nearly the operating temperature approaches the adiabatic saturation temperature, the higher will be the SO_2 removal efficiency, and the harder the process is to control. Thus, the approach to saturation temperature (AST) is an important factor in dry or semi-dry scrubber operation.

Conventional spray dryer systems cannot operate at an AST below about 10°C (18°F) without solids buildup caused by high moisture content. Because of the improved heat- and mass-transfer in the GSA reactor, the injected lime slurry dries almost completely, even at relatively close approach to the adiabatic saturation temperature. This is evidenced by the fact that the GSA by-product solids have less than 1% moisture, even when operating at an AST as low as 4°C (7°F).

Characteristics of By-product Solids

The solid by-product generated in the GSA process consists mainly of calcium sulfite and calcium sulfate. The low moisture content of the solids accounts for the lack of dust buildup on the system walls., Conventional spray dryers avoid this problem by operating at higher ASTs, but as a consequence, the SO_2 removal efficiencies are lower than those achieved by the GSA process.

Analysis of the GSA solids -supports the theory that the dry recycle solids are coated with a thin layer of fresh lime slurry on each pass through the reactor. Cross-sectional photomicrographs of large particles removed from the recycle stream show a central core surrounded by a series of rings similar to tree rings. Spectral analysis of these layers has determined that the central core of the particles is fly ash, while surrounding rings are composed of calcium-sulfur compounds.

Air Toxics Removal

The potential impacts of Title III of the CAAA have resulted in increased emphasis by electric utilities on the measurement and control of air toxics, also referred to as hazardous air pollutants (HAPs). The air toxics studied in this project were HF, HCI, and the following trace metals: antimony, arsenic, barium, cadmium, chromium, cobalt, lead, manganese, mercury, selenium, and vanadium.

Air toxics measurements were performed as part of the demonstration program. Energy and Environmental Research Corporation of Irvine, California participated in these tests.

C. Project Objectives/Results

As part of the third round of the CCT program, AirPol Inc. participated in a cooperative agreement for the design, installation, and testing of the GSA system for FGD at the NCER, operated by TVA. This project was the first North American demonstration of the GSA system for FGD service at a coal-fired utility plant. This demonstration project was designed to confirm pilot scale results and demonstrate process operation at a large scale (10 MWe). The performance goals and results are summarized as follows:

1. **Demonstrate SO_2 Removal in Excess of 90% when Burning High-Sulfur U.S. Bituminous Coal**

   Greater than 90% removal Of SO_2 was achieved when firing three bituminous coals, with a sulfur content ranging from 2.6 to 3.1 %.

2. **Optimize Design Parameters to Achieve Maximum Efficiencies of Lime Utilization and SO_2 Removal**

   The target level of 90% SO_2 removal was achieved at a 1.3 molar ratio of fresh lime (calcium) per mole of sulfur dioxide in the incoming flue gas.

3. **Compare Performance and Cost with Existing FGD Technologies**

   The estimated capital cost for a G SA system is about 30% less than that for a wet limestone FGD unit providing the same SO_2 removal for a given coal sulfur content. The levelized annual costs for GSA are significantly lower than those for wet limestone FGD for comparable unit sizes.

4. **Determine the Air Toxics Removal Performance**

   Trace metals were effectively removed by the combination of GSA and particulate removal, with efficiencies ranging from about 77% to nearly 100% depending on the metal. Removal rates of HCI and hydrogen fluoride (HF) were in excess of 99%. Additional discussion of HAPs removal is given below.

5. **Compare the Emissions Between a GSA System with an Electrostatic Precipitator and a GSA System with a Fabric Filter**

   The SO_2 removal efficiency of the GSA system using a fabric filter for particulate removal was about 3 to 5 percentage points higher than that achieved when using an ESP under comparable conditions. Particulates removal exceeded 99.9% for both systems. Air toxics removal was similar for both systems.

D. Environmental Performance

SO_2 Emissions

With an overall SO_2 emissions reduction of 90% while burning coal containing 2.6% S the SO_2 stack emissions were about 0. 13 kg/GJ (0.3 lb/10^6Btu), which is only one-quarter the NSPS value of 0.52 kg/GJ (1.2 lb/10^6Btu).

Particulate Emissions

Emissions of particulates in the demonstration program were about 6.5 g/GJ (0.015 lb/10^6Btu), which is only one half the NSPS level of 12.9 g/GJ (0.03 lb/10^6 Btu). Additional discussion of particulate capture is given below.

Air Toxics Emissions

Most of the air toxics were removed by the combination of the GSA reactor and the particulate removal system, which, as mentioned previously, consists of either an ESP or a fabric filter. Performance was comparable for the GSA/ESP combination and the GSA/fabric filter combination.

E. Post Demonstration Achievements

Since completion of the demonstration project, TVA has continued operating the GSA unit at the NCER, gaining additional operating experience. AirPol has standardized the process design and equipment sizing for commercial installation. Equipment design has been simplified, resulting in reduced material and construction costs.

AirPol has been contracted to supply a GSA FGD system for a 50 MWe municipal boiler in Hamilton, Ohio, as its first commercial utility installation in the U.S. In 1994, the state of Ohio, in conjunction with the Ohio Coal Development Office, awarded Hamilton a grant for this installation. To meet air pollution control requirements it has been necessary to bum relatively expensive low-sulfur coal in this plant. Use of the GSA system will allow the city to meet environmental regulations while firing high-sulfur Ohio coal.

A GSA system for SO_2 removal was recently installed at an iron ore sintering plant in Sweden having a flue gas flow rate equivalent to that of a 135 MWe power plant boiler. Initial operating experience has been favorable. Negotiations are underway for a GSA installation at a 12 MWe cogeneration plant in Asia. For both of these applications, the success of the CCT demonstration program at the NCER was a major factor in the decision to employ GSA technology.

III. Operating Capabilities Demonstrated

A. Size of Unit Demonstrated

As indicated above, the host site for this project was the NCER, located at TVA's Shawnee Fossil Power Plant near Paducah, Kentucky. A slipstream of flue gas from the Unit 9 boiler is routed through the NCER test facility. The boiler is rated at 150 MWe, and the slipstream flow rate is equivalent to about 10 MWe. This capacity was considered sufficient to provide the data required for scale-up to commercial operation.

For the demonstration project, the GSA system was retrofitted upstream of an existing ESP. As part of the project, an available fabric filter was also tested. The fabric filter is a small, pulse-jet baghouse (PJBH) that treats a slipstream of the flue gas equivalent to I MWe. Despite the relatively small size of the PJBH, meaningful performance data were obtained. The PJBH was tested in two modes during separate phases of the project: treating flue gas from the GSA system outlet and from the ESP outlet.

B. Performance Levels Demons

SO_2 Removal Efficiency

For a typical run in the demonstration program when firing 2.6% S coal, the SO_2 content of the flue gas entering the GSA reactor from the boiler was 1873 ppm, while the SO_2 in the stack gas was 150 ppm, representing a removal efficiency of 92%. This stack emission rate corresponds to about 0.13 kg/GJ (0.3 lb/10^6 Btu), which is well below the NSPS value of 0.52 kg/GJ (1.2 lb/10^6 Btu).

The SO_2 removal efficiency of the GSA process is comparable to that achieved by wet limestone scrubbing. Several factors account for the excellent performance of GSA. As discussed previously, SO_2 absorption is enhanced by minimizing the AST. The GSA process can operate at very low ASTs due to its excellent heat- and mass-transfer characteristics. The demonstration project showed that the GSA system can operate successfully, without dust buildup, at an AST as low as 3 to 6°C (5 to 10°F).

Lime Consumption

Lime consumption in the GSA process ranges from about 1.3 to 1.4 moles of calcium per mole Of SO_2 in the inlet gas, which is relatively low compared with other dry or semi-dry FGD processes. This excellent performance can be attributed to the high recycle ratio of particles coated with lime. Lime consumption is discussed in greater detail in subsequent sections.

ESP vs. PJBH Performance

An objective of the demonstration program was to compare emissions for the GSA/ESP combination with those for the GSA/PJBH combination. The ESP used at the NCER is a relatively modem, four-field unit with a specific collection area (SCA) of about 86.4 $M^2/M^3/S$ (440 ft^2/1000 acfm). This SCA is approximately equivalent to that of several full-scale ESPs installed on the TVA power system. The bags used in the PJBH were made of polyphenylene sulfide needle felt, having a weight of 542 g/m^2 (16 oz/yd^2).

As would be anticipated, most of the SO_2 removal occurs in the reactor/cyclone. The test results showed that, when the PJBH was used for dust collection, the overall SO_2 removal rate was about 3 to 5 percentage points higher than when using the ESP. The higher SO_2 removal rate in the GSA/PJBH system is due to the intimate contact between the residual SO_2 and the still reactive solids in the filter cake on the bags. The comparative results are given in Figure 5, with SO_2 removal efficiency shown as a function of calcium/ sulfur ratio.

Particulate emissions throughout the demonstration program, when using either the ESP or the PJBH for dust control, were about 6.5 g/GJ (0.015 lb/10^6 Btu), or one-half the NSPS level for particulates of 12.9 g/GJ (0.03 lb/10^6 Btu). This represents a particulate removal efficiency in excess of 99.9%.

When the PJBH was operated in series with the ESP, the particulate emission rates were even lower, about 0.9 g/GJ (0.002 lb/10^6 Btu), which is more than an order of magnitude below the NSPS for particulates. If extremely high removal efficiencies are required, installing a fabric filter downstream of the ESP is a very effective arrangement.

For air toxics, both the GSA/ESP combination and the GSA/PJBH combination proved capable of removing most of the HAPs from the flue gas as noted above.

Reliability

The GSA system operated with a high degree of reliability throughout the demonstration program. During the 28day run of the GSA/ESP system, SO_2 removal efficiency exceeded 90 percent, even when the boiler was switched to a higher sulfur coal. The switch to the higher sulfur coal demonstrated the system's flexibility over a range of coal sulfur levels. The system remained on-line for the entire 28-day period. This is consistent with extensive experience with commercial GSA system installations in MSW service, which operate reliably around the clock, and have demonstrated availability of close to 100 percent.

C. Major Operating Variables Studied

Coals Tested

Three western Kentucky, high-sulfur bituminous coals were tested in the GSA project: Peabody Martwick, Emerald Energy, and Andalex**.** Coal analyses are given in Table 1. Due to temporary problems encountered in obtaining the Andalex coal, a switch was made to burning Warrior coal, a higher-sulfur (3.5%) coal, for about I week during the demonstration run.

Operating Conditions

Typical operating conditions were as follows:

Flue gas flow rate	9.5 Nm3/s (20,000 scfm)
Fly ash loading	4.6 g/M3 (2.0 gr/acf)
Calcium/sulfur molar ratio	1.3-1.4
Temperature of flue gas from boiler	160°C (320°F)
Flue gas adiabatic saturation temperature	52°C (126°F)
Absorber operating temperature	62°C (144°F)
Approach to saturation temperature	10°C (18°F)

The three major process variables studied in this project were operating temperature, calcium/sulfur ratio, and coal chloride content. Preliminary testing also was done to evaluate three other parameters: flue gas flow rate, inlet fly ash loading, and solids recycle rate. Data on the latter variables were incorporated in performance correlations developed in the project.

Effects of Major Process Variables

Figure 3 shows the effects of operating temperature and calcium/ sulfur ratio on SO_2 removal efficiency. The temperature effects are correlated in terms of AST. From an operational standpoint, AST is a function of the flue gas composition and temperature and the rate of flow of water in the slurry injected into the absorber via the spray nozzle. Thus, although AST is a dependent variable, it is useful in developing performance correlations.

SO_2 removal efficiency increases with decreasing AST; that is, the closer to the adiabatic saturation temperature, the greater the rate of SO_2 absorption. SO_2 removal efficiency also increases with increasing calcium/sulfur molar ratio. At an AST of 10°C (18°F), the target SO_2 removal efficiency of 90% is achieved at a calcium/sulfur ratio of 1.3.

It has been established in previous work that the presence of chlorides in the coal feed enhances SO_2 absorption efficiency in FGD. In the GSA demonstration project, this effect was studied by adding calcium chloride to the sorbent slurry to simulate coals of varying chloride content. The data in Figure 3 represent operation with no chloride addition. The effect of chlorides is given in Figure 4, which shows SO_2 removal efficiency as a function of calcium/sulfur ratio at three chloride levels. In Figure 4, the amount of chloride is expressed as the percentage of chloride added to the fresh lime feed.

Air toxics testing was part of the project. The GSA system provided substantially complete removal of HCI and HE Removal rates for trace metals were high, exceeding 98% for most metals. The trace metals results are shown in Figure 6. Figure 6 differentiates between the removal efficiency in the GSA absorber/ cyclone and the removal achieved by the total system including absorber, cyclone, and dust collector. The relative amounts of trace metals removed in the GSA absorber/cyclone and in the dust collector vary greatly among the metal species. Differences in trace metals removal efficiency between the ESP and the PJBH were not significant.

GSA System Capabilities

The GSA system was operated in a 28-day continuous demonstration run with the ESP and separately in a 14-day demonstration run with the PJBH. Two important findings were as follows:

- For the GSA/ESP system, SO_2 removal efficiency exceeded 90%, even when the boiler was switched to the higher sulfur coal. This performance demonstrated the flexibility of the GSA process over a range of coal sulfur levels.

- For the GSA/PJBH system, SO_2 removal levels reached as high as 96%. This increase reflects the added SO_2 removal, which takes place in the fabric filter, as, discussed previously.

D. Operating and Maintenance Experience

The GSA system tested at TVA's NCER was trouble free, with no major problems encountered during the entire test program. All equipment and control instruments operated as anticipated without extra attention. The GSA unit is easy to operate and maintain, which is mainly attributable to a simple design, a feature that withstood the test of scale up to demonstration size.

There are no moving parts in contact with the flue gas. The spray nozzle assembly is routinely alternated with a spare unit once per week, a procedure that takes less than 5 minutes and is done while the system is in operation. The orifice washer (a low-cost item) is replaced and the assembly is cleaned and made ready for the following week's replacement. This simple procedure for nozzle replacement is feasible because the system operates under a slight negative pressure, and quick-connect fittings are used.

The orifice diameter of the GSA injection nozzle is larger than that used in a conventional spray dryer, and there is little chance for it to plug. Both the reactor and the cyclone are constructed of unlined carbon steel, which has proven to be corrosion free. Of the commercial installations in MSW service, none requires a dedicated maintenance crew. Also, most installations do not require a dedicated operator; the incinerator personnel operate the GSA system.

When the PJBH was in use, the filter cake on the bags was relatively easy to dislodge, and no problems were encountered in cleaning the bags using a low-pressure, high-volume ambient air stream delivered by a rotating manifold.

F. Commercialization of the Technology

Current Status

Commercial application of GSA technology has begun in the U.S. in Hamilton, Ohio.

The GSA system recently installed at an iron ore sintering plant in Sweden uses a single GSA absorber and two parallel cyclones. The absorber used in that installation represents approximately the maximum feasible reactor size based on flue gas flow rate considerations. Other projects are planned and the larger size Swedish project installations will most likely use parallel, modular units.

Future Projects

As part of the demonstration project, correlations were developed which characterize the performance of the GSA system. These correlations are being used in the design of larger units. Further experience will permit refinement and enhancement of the correlations. Future installations also will provide additional information on scale up.

Additional studies are planned to determine the minimum collection area required for particulate control and the effect of lime properties on GSA system performance. Further work is contemplated on developing uses for the byproduct solids.

IV. Market Analysis

A. Potential Markets

The potential market for GSA includes coal-fired utility and industrial boilers firing medium-to high-sulfur coals in both new installations and retrofit applications. Because of the relatively small footprint of the GSA equipment, the process can readily be adapted to retrofit situations, and an existing ESP can be used, if available.

The GSA concept has now been applied commercially at the 135 MWe scale, and further capacity increases should be readily accommodated. Where boilers are now fired with compliance coal, use of GSA could permit switching to lower-cost, high-sulfur coals. AirPol estimates the market for the GSA process to be $300 million over the next 20 years.

B. Economic Assessment for Utility Boiler Applications

As part of the CCT Demonstration Program, a cost estimate for the GSA process was performed by Raytheon Engineers and Constructors, following guidelines established by the Electric Power Research Institute (EPRI). For comparison, the economics of conventional FGD using wet limestone forced oxidation (LSFO) also were evaluated, using a consistent set of design and economic premises.

The economics assumed a 300 MWe boiler with a moderately difficult retrofit, burning 2.6% sulfur coal, and a design SO_2 removal efficiency of 90%. For GSA, a lime feed rate equivalent to 1.30 moles of calcium per mole of SO_2 in the gas inlet stream was assumed. The economics are summarized in Table 2.

The total capital requirement for the GSA process is substantially lower than that for LSFO ($149/kW vs. $216/kW) for the example given. The lower capital for GSA is primarily due to lower costs in the SO_2 removal area. Levelized annual costs (15-year basis, current dollars) are 10.9 mills/kWh for GSA compared with 13.0 mills/kWh for LSFO. These levelized costs correspond to $602/ton of SO_2 removed for GSA and $718/ton for LSFO.

The major operating cost for GSA is the lime sorbent. The GSA process requires a higher molar ratio of sorbent to inlet SO_2 than does LSFO, and the price of lime is higher than that of limestone per mole of calcium. However, the total levelized cost for GSA is less, primarily because of reduced capital and lower power consumption.

Also, the capital cost of the GSA system is about 10% lower than that for a conventional spray dryer system.

V. Conclusions

All of the major objectives of the GSA demonstration were successfully achieved, as indicated by the following findings:

- SO_2 removal efficiency of 90% can be achieved at a modest level of lime consumption (1.3 moles calcium/mole inlet SO_2) when treating flue gas resulting from combustion of high-sulfur coal.
- SO_2 removal efficiency is enhanced by the presence of chlorides.
- Most of the SO_2 removal takes place in the reactor/cyclone. There is very little SO_2 removal in the ESP, but use of a fabric filter instead of an ESP provides several percent of additional SO_2 removal.
- The GSA system has very low particulate emission rates, well below the NSPS, when equipped with a four-field ESP with an SCA of at least 86.4 $M2^2/M^3/S$ (440 ft^2/1000 acfm).
- The GSA system equipped with conventional particulate removal equipment (either an ESP or a PJBH) removes a high percentage of the trace metals. Substantially all of the HCI and HF are removed from the flue gas by reaction with lime in the GSA absorber.
- By-product from the GSA system is a dry solid. Since it does not leach, it can be disposed of as landfill without further treatment. The by-product, which contains both fly ash and unreacted lime, can also be converted to a pozzolanic cement by addition of water.
- Corrosion in the GSA system is negligible. The system can be fabricated from carbon steel rather than more expensive alloys.
- The GSA unit operates with a high degree of reliability. The system requires little maintenance, no dedicated operator, tolerates changes in coal sulfur content readily, and has a level of availability at or near 100%.
- The GSA process has a lower capital cost than wet limestone FGD.

In summary, the GSA system has been shown to be a low-cost alternative to other FGD systems. SO_2 removal efficiencies for GSA are comparable to those for wet FGD and significantly higher than those for dry and many other semi-dry systems. The GSA system meets NSPS requirements for SO_2 emissions and provides substantial removal of air toxics. Particulate control can be achieved by either an ESP or a fabric filter.

Ground space requirements for the primary equipment are modest. GSA lends itself well to retrofit installations, where in many cases an existing dust collection device can be utilized. It has been successfully demonstrated on a commercial scale, and application in the marketplace has begun.

VI. References

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9) "The Clean Coal Technology Program 10 MWe Demonstration of Gas Suspension Absorption for Flue Gas Desulfurization," AirPol Inc., Proceedings of the U.S. Department of Energy Third Annual Clean Coal Technology Conference (Chicago, Illinois), September 1994.

10) "The Clean Coal Technology Program 10 MWe Demonstration of Gas Suspension Absorption for Flue Gas Desulfurization," AirPol Inc., Proceedings of the U.S. Department of Energy Second Annual Clean Coal Technology Conference (Atlanta, Georgia), September 1993.

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TABLES

Table 1. Coal Properties

	Peabody Martwick	*Emerald Energy*	*Andalex*
Proximate Analysis, wt%			
Fixed Carbon	44.3	45.8	45.5
Volatile Matter	35.8	37.6	35.4
Moisture	11.3	10.1	8.9
Ash	8.6	6.5	10.2
Total	**100.0**	**100.0**	**100.0**
Higher Heating Value, Btu/lb			
As Received	11,634	12,065	11,725
Dry	13,117	13,420	12,870
Higher Heating Value, MJ/kg			
As Received	27.1	28.1	27.3
Dry	30.5	31.2	30.0
Ultimate Analysis, wt% [a]			
Carbon	72.99	76.26	69.42
Hydrogen	4.92	5.72	5.03
Sulfur	3.05	2.61	3.06
Oxygen	7.65	6.83	9.91
Nitrogen	1.65	1.26	1.39
Chlorine	0.02	0.04	0.04
Ash	9.72	7.28	11.15
Total	**100.00**	**100.00**	**100.00**

[a] Dry basis

Table 2. Economic Comparison

300 MWe, 1990 $, 2.6% S Coal
15-Year Levelization

Process	*GSA*	*LSFO*
Capital Requirement, $/kW		
Reagent Feed	26.3	36.7
SO_2 Removal	42.2	71.1
Flue Gas Handling	18.9	24.0
Solids Handling	4.6	6.7
General Support	1.4	1.9
Additional Equipment	4.1	4.0
Total Process Capital	**97.5**	**144.4**
Total Capital Requirement	**159.4**	**216.2**
Levelized Cost, Mills/kWh		
Capital Charge	5.40	7.30
Fixed O&M Expense	2.35	2.81
Variable O&M Expense	3.16	2.93
Total Levelized Cost	**10.91**	**13.04**
Levelized Cost, $/ton SO_2 Removed		
Capital Charge	291	394
Fixed O&M Expense	129	155
Variable O&M Expense	182	169
Total Levelized Cost	**602**	**718**

FIGURES

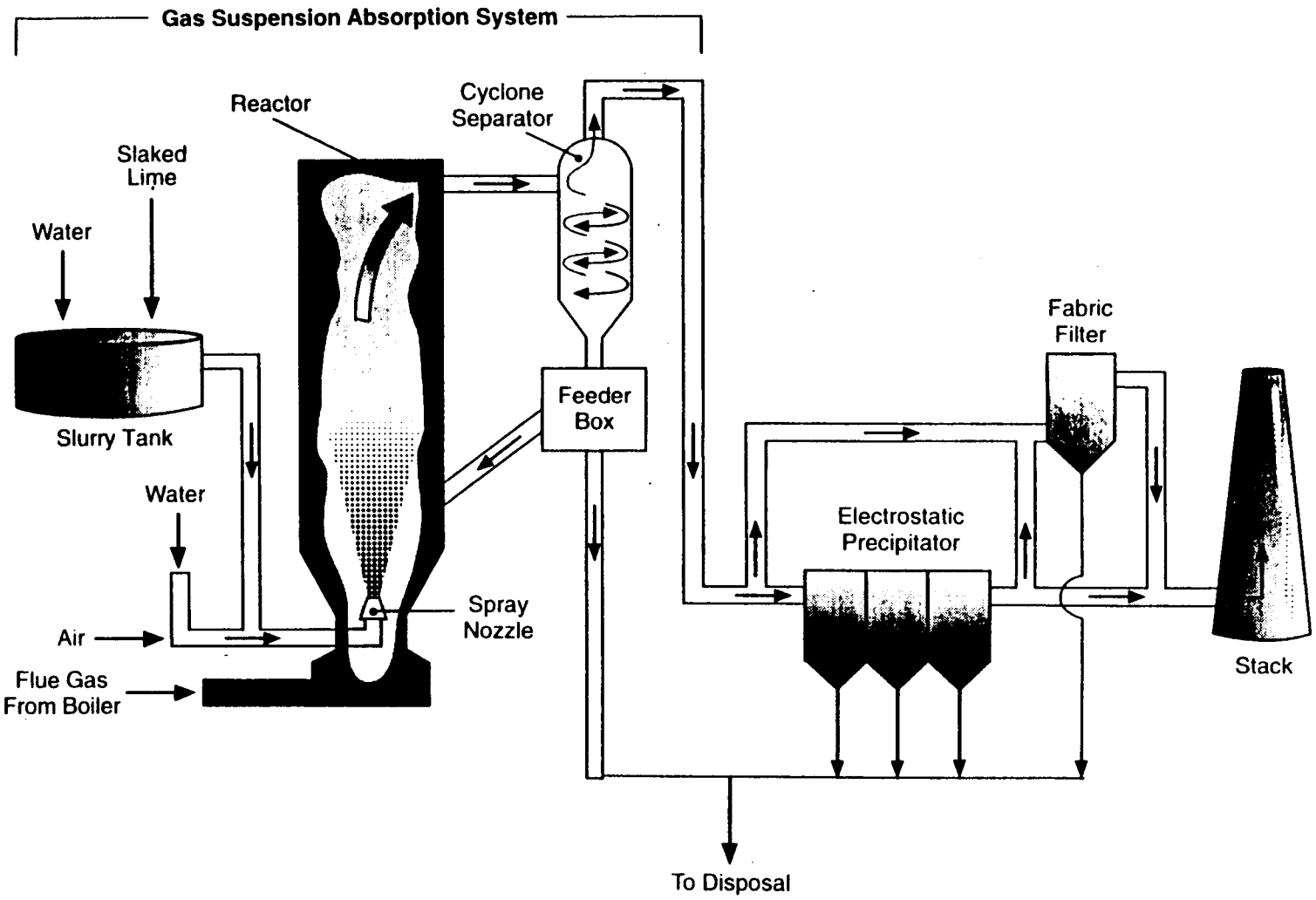


Figure 1. Process Block Flow Diagram

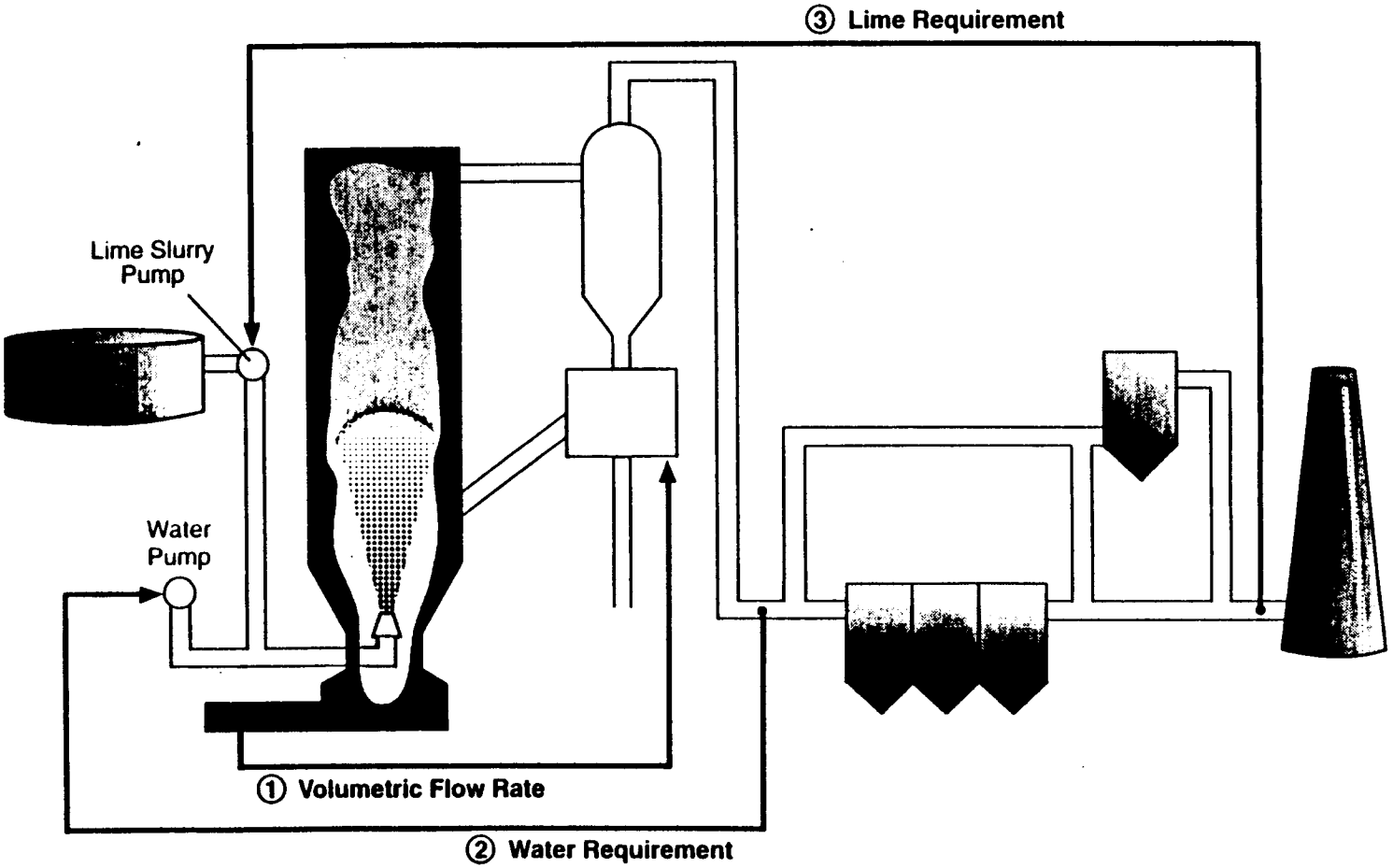


Figure 2. Control Scheme for the GSA System

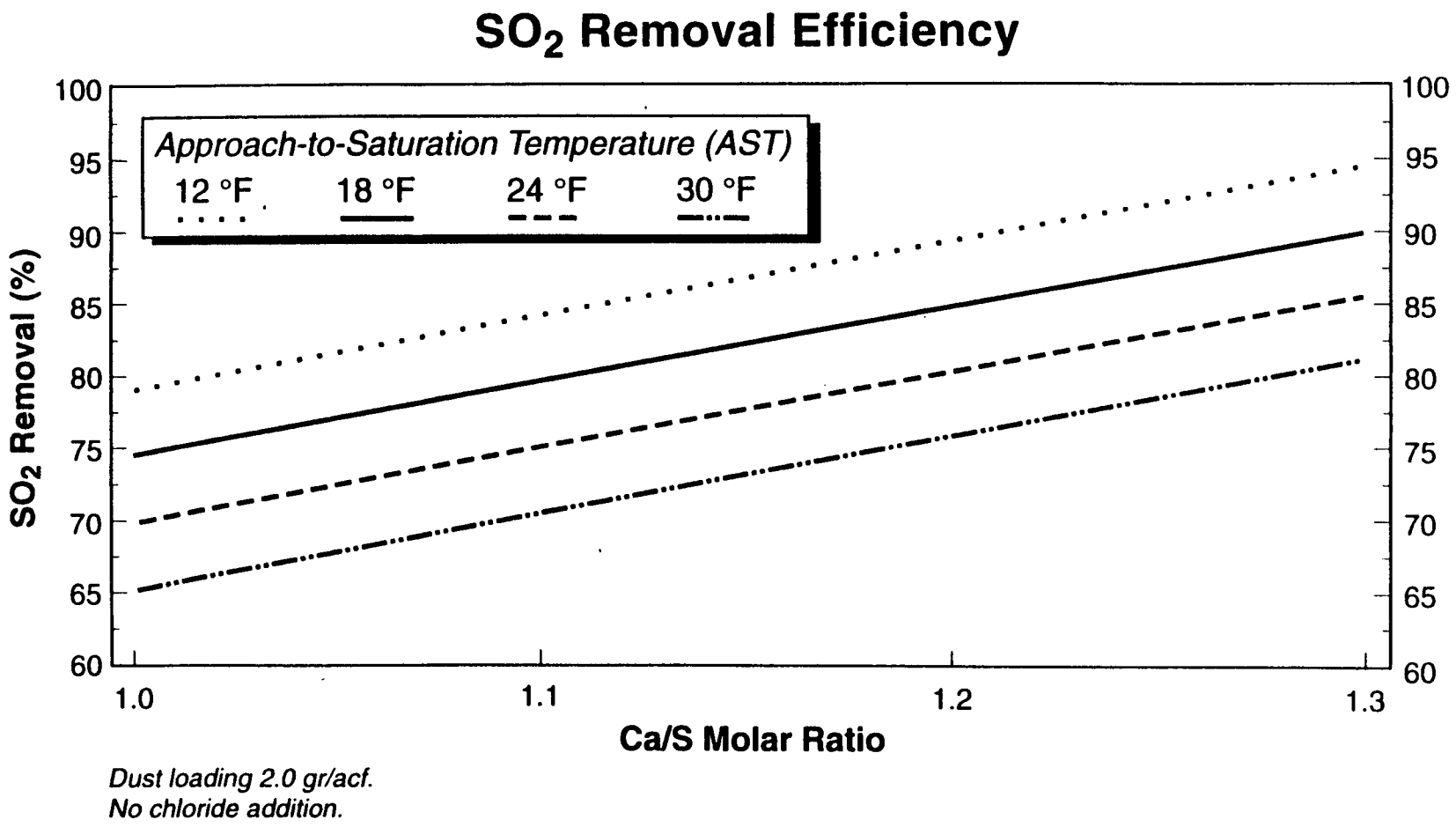


Figure 3. Overall System SO_2 Removal Efficiency

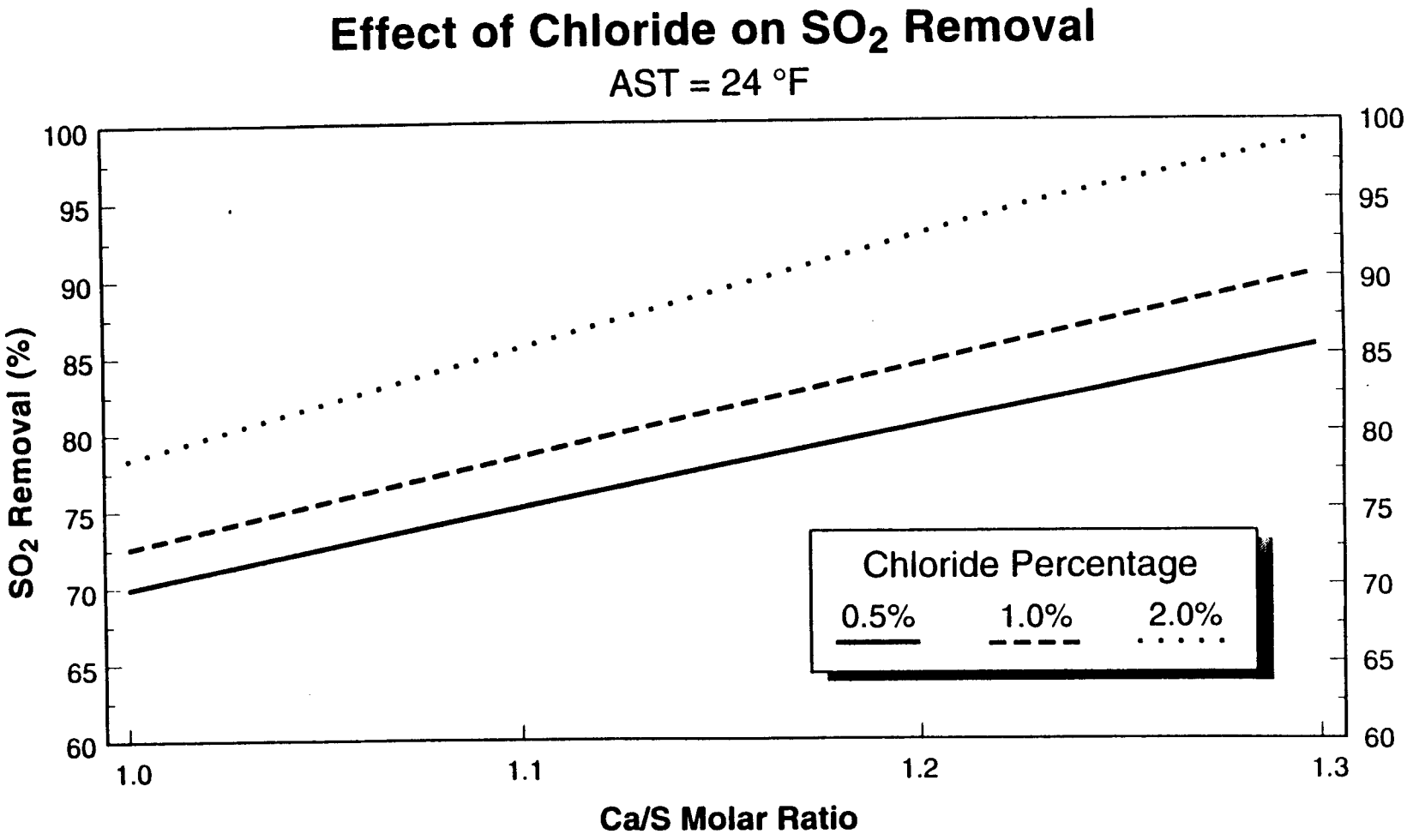


Figure 4. Effect of Chloride on SO_2 Removal

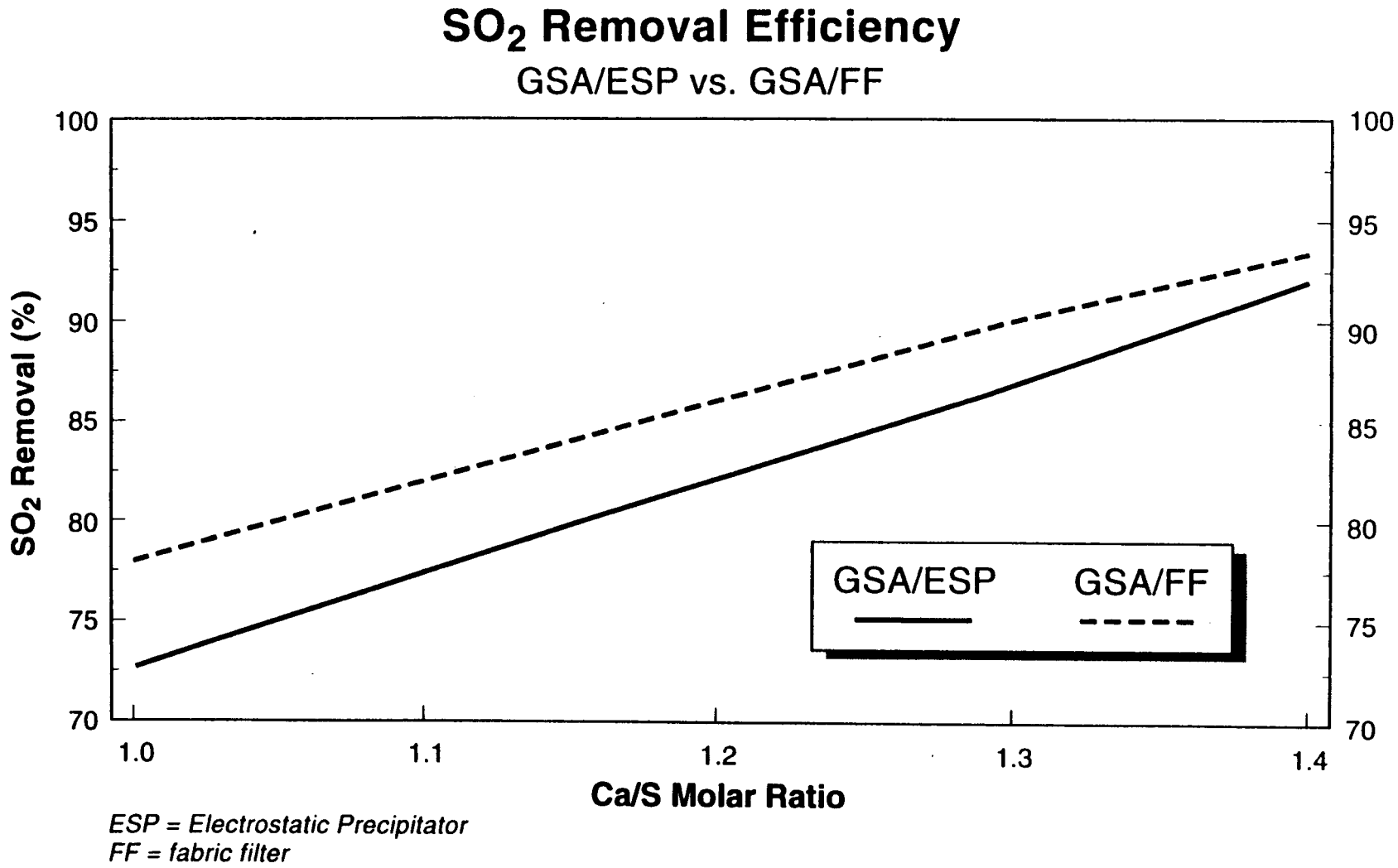
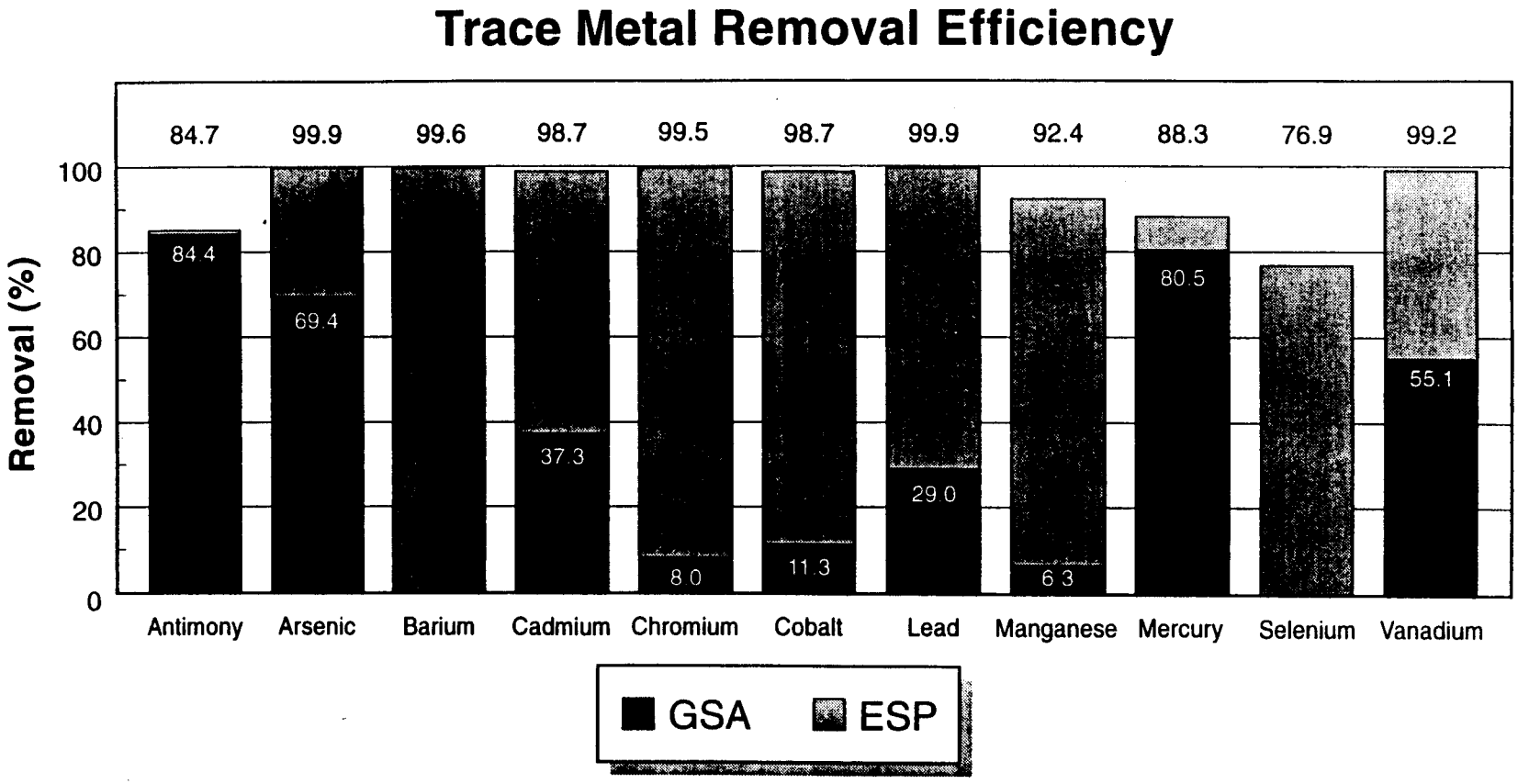


Figure 5. Comparison of SO_2 Removal Efficiencies with GSA/ESP and GSA/FF Options



Test results based on an average of three measurements.

Figure 6. Trace Metal Removal for the GSA/ESP System