FGD Performance Capability

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ABSTRACT

Utilities continue to specify FGD system performance at increasing SO_2 removal efficiencies in response to permit requirements, local consent decrees and the potential need to install CO_2 controls in the future. Environmental groups are also pressuring public utility commissions to push pulverized coal power plants to achieve emission levels similar to IGCC and NGCC. This paper summarizes FGD system design and operation upgrades that may be necessary to achieve 99+% SO_2 removal on a continuous basis, resulting in single digit SO_2 ppm emission rates. This paper will also address several multi-pollutant emission control technologies that can achieve or show promise of achieving very high levels of SO_2 removal in addition to removal of NO_x and/or mercury.

INTRODUCTION

The FGD market in the U.S. has been working at near capacity for the last few years. The regulatory environment for coal fired units has been more and more restrictive due to the perception of coal fired generating facilities as being dirty in comparison to gas fired plants and other renewable energy options. But coal still plays an integral part in the generating mix in the U.S. due to ever increasing demand for electricity. In response to public perception, the state and federal regulatory agencies continue to promulgate more restrictive legislation for coal fired plants, in some cases requiring 98-99% reduction of SO_2 from new coal fired generating plants. The control of CO_2 generated by new and existing coal plants will further push the SO_2 reduction technologies to reduce their SO_2 emission levels to the single digits to help reduce the operating costs associated with some of the CO_2 removal systems. This paper provides a summary of the gains in FGD system performance that are now being offered in the U.S. utility market today, and describes some of the new technologies that may meet these requirements in the future.

EXPERIMENTAL METHODS

Some of the major FGD systems suppliers serving the U.S. utility industry are listed below:

- Siemens-Wheelabrator
- Chiyoda
- Babcock & Wilcox
- Babcock Power
- Alstom
- Advatech/Mitsubishi
- Hitachi America
- Marsulex

In 2006, it was estimated that these companies had combined sales for more than 90% of the wet FGD market in the United States.

URS Washington Division contacted many of these major vendors of FGD equipment to discuss how they would plan to address the need for increased SO_2 reduction efficiency for continuous, long-term operation of their FGD systems. Specific installations were identified that have already achieved 98% to 99% removal on a continuous basis. System upgrades that allowed these high levels of performance were also identified, including modifications that have been incorporated into recent installations, or could be used in existing FGD systems to achieve outlet emissions that approach single digit ppm levels. The information from the conference calls and supplier visits was combined with material from previous EPRI reports, conference proceedings, and public domain literature to complete the documentation for this paper. All of the information and data from these sources were compiled and are presented in multiple EPRI reports that were published in 2007-2008.

Much of the discussion surrounding FGD systems focuses on wet systems as they have a distinct advantage over dry FGD systems in achieving 99+% SO_2 removal. In addition to FGD processes, the report contains process descriptions and development information on multi-pollutant processes that have the capability or show promise to achieve 99+% SO_2 removal. The discussion of these processes also includes their capabilities to remove NOx and mercury simultaneously.

THE NEED FOR HIGHER SO_2 REMOVAL EFFICIENCIES

Power generation companies in the U.S. are facing an increasingly stringent regulatory landscape, not only from the EPA, which has implemented CAIR and visibility (and attempted mercury) regulations in the last few years, but also from states, some of which have established SO_2 emission limits lower than the federal emissions standards. Most power producers have concluded that continuing public concerns regarding the overall impacts of coal-fired power generation will result in even more stringent limits of NO_x, SO_2,

mercury, and primary particulates in the future. In addition, public pressure on regulators to mandate consideration of alternatives to pulverized coal (PC) fired generation because of their carbon footprint is on the rise. In response to public concern and pressure, future state and/or federal regulatory limits on SO_2 emissions could require FGD process to reduce SO_2 emission rates to single digit ppm levels.

One of the alternatives to PC fired generation identified as the preferred method to achieve low emission rates by some environmental groups and regulatory agencies is Integrated Gasification Combined Cycle (IGCC). Although very few of these plants have been built, and many have recently been cancelled due to costs or regulatory uncertainty, they were becoming the emissions benchmark for coal-fired power generation technologies. As a result, utilities that have decided that PC-fired plants are more viable to meet increasing load demand because they are more cost-effective than IGCC designs may face regulatory requirements for new and retrofit FGD systems that can reduce sulfur emission to levels achieved by IGCC. Advocates of Natural Gas Combined Cycle (NGCC) are going one step further and lobbying to have these systems replace coal-generated power outright because NGCC emits virtually no SO_2 and reduces green house gas (GHG) emissions.

Green house gas emissions, especially CO_2, play a role in the global warming theory. Public attention has driven federal and state regulators toward enactment of regulations to reduce CO_2 emissions from new and existing power plants. New technologies are currently under development for pre- and post-combustion CO_2 reduction, as well as modifications to the combustion process itself. Some of the post-combustion CO_2 removal processes operate more efficiently and are more cost-effective when inlet SO_2 concentrations are maintained at very low levels.

All of these factors are leading utilities toward FGD processes that can achieve SO_2 emission levels that approach the single digit ppm level when firing all types of coal in PC plants. To meet the challenges for near-zero SO_2 emissions from PC plants, it is likely that FGD systems will have to incorporate design modifications to enhance SO_2 reduction, and operating practices will have to be modified to achieve the lower SO_2 outlet concentrations.

ACHIEVING HIGHER SO_2 REMOVAL EFFICIENCIES

Utilities are already installing FGD systems with performance guarantees of 98+% SO_2 removal. These systems incorporate some of the latest absorber design upgrades and modified operating conditions specified by the FGD original equipment manufacturers (OEMs). However, it should be noted that these newest installations are designed to meet the contract performance test requirements while the supplier staff are on the site, and typically the FGD system guarantees do not apply to the actual long-term operating performance. The operating procedures of plant staff will tend to be different from those used by the OEM staff, and changes in equipment performance as the system ages will tend to result in some reductions in the reduction efficiency capabilities of the FDG systems. Therefore, additional

design upgrades may still be necessary to achieve continuous single digit SO_2 emission rates during long term operation.

Utilities will also need to consider adopting a different operating philosophy in order to achieve 99+% SO_2 removal on a multi-day rolling average basis. To achieve these single digit SO_2 levels, the utilities will need to place greater emphasis on monitoring FGD performance including augmenting operating staff with engineering staff who can appropriately respond to changes in process chemistry due to system upsets, and paying greater attention to the accuracy and performance of process instrumentation and equipment maintenance. In essence, U.S. utilities would need to adopt the Japanese FGD operating philosophy, which includes hands-on involvement of operating engineers on a day to day basis, regular preventative maintenance to instruments and operating components, and consistent vigilance by operating staff to ensure that the desired process chemistry is maintained within specified ranges so that the FGD performance can be maintained at it maximum capability.

FGD System Design Modifications

The following sections focus on the latest state-of-the-art FGD system design innovations that are allowing these systems to achieve SO_2 reductions above 99% removal for high sulfur coals, and above 98.5% for low sulfur coals, resulting in SO_2 emission rates that approach the single digit ppm level. It is assumed that the reader has a basic understanding of the FGD systems, including design and reaction chemistry, offered by the major FGD vendors that were mentioned earlier. Only brief descriptions of each process are given here, focusing on those elements in the design and operation of these systems that will contribute to increased SO_2 removal.

Chiyoda CT-121 Jet Bubbling Reactor (JBR)

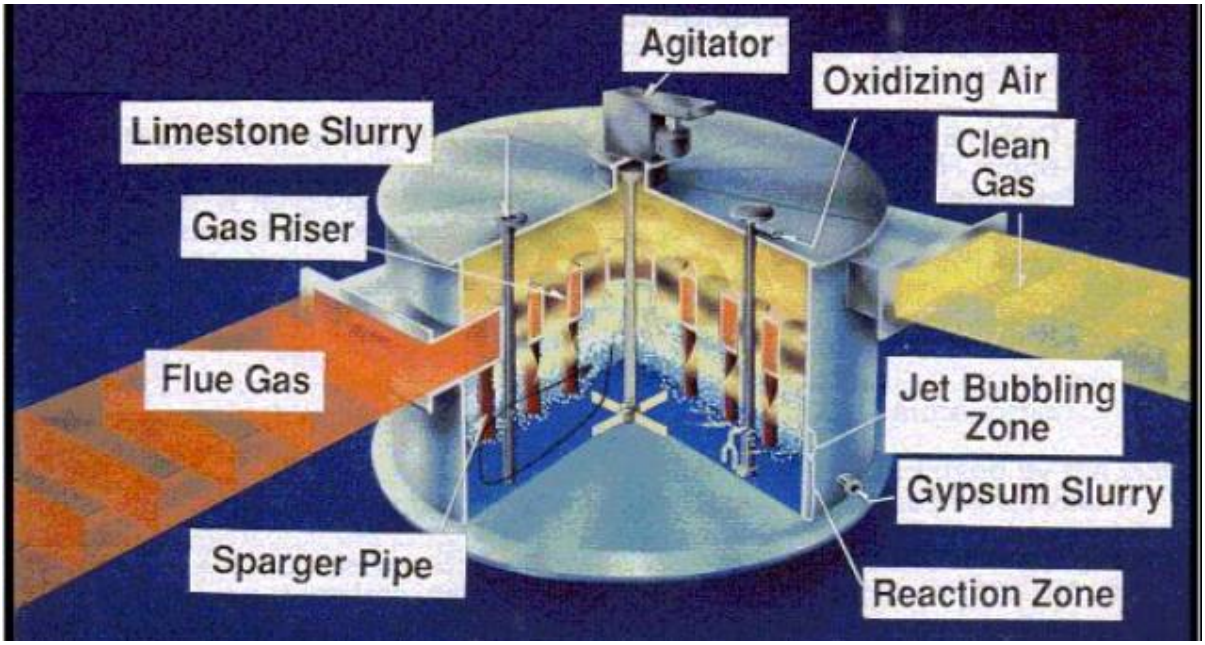
The CT-121 FGD process was developed more than 20 years ago by the Chiyoda Corporation in Japan. They have since licensed the technology to engineering and construction contractors throughout the world. The CT-121 process utilizes the same reaction chemistry as the wet Limestone with Forced Oxidation (LSFO) process.

The major difference between the CT-121 process and other LSFO FGD systems is the Jet Bubbling Reactor that serves as the SO_2 absorber, oxidizer, and reaction crystallizer in one vessel. Flue gas from the boiler is cooled using a water quench and then is forced down through a series of sparger tubes positioned in a tube sheet above the reaction tank and immersed in the limestone/gypsum slurry (see Figure 1). The gas flows down through the tubes and then bubbles upward through the absorber slurry to form a froth layer. The froth provides a gas-liquid contact zone to promote SO_2 dissolution into the reaction tank slurry.

Chiyoda has stated that the CT-121 process can achieve SO_2 removal of more than 99%. They have some limited experience on very high SO_2 inlet concentrations (4000 ppm), and

have demonstrated that achieving 99+% removal on these units is relatively easy. Chiyoda has also provided guarantees for 99+% removal on medium sulfur units, in particular the Shinko-Kobe Unit #2 with a design sulfur content of 0.93% S on these two coal fired units (700 MW). At this facility, Chiyoda guarantees greater than 99% SO_2 reduction from an inlet flue gas stream containing 840 ppm SO_2. The actual condition for the performance test was 320 ppm, and the Chiyoda system attained 99.8% SO_2 reduction under those conditions.

Figure 1: Chiyoda CT-121 Schematic Flow Diagram (Round Vessel)



These high reduction efficiencies are achieved with an increase in pressure drop across the absorber (added power consumption) and operation at a higher slurry pH. The CT-121 system operates at a higher pressure drop than an open spray tower design because the flue gas is bubbled through the slurry. This higher pressure drop, and resultant increase in ID fan power consumption is offset by the fact that the CT-121 process does not use large recycle pumps to feed slurry to the absorber vessel. In order to achieve higher reduction efficiencies, the CT-121 absorber can be run with a higher pressure drop by increasing the depth of the slurry through which the flue gas must flow to reach the top of the froth layer. This increases the contact time of the SO_2 and the slurry, promoting greater removal, but it also increases the power consumption of the system.

The latest CT-121 installations have been able to reduce their power consumption 15% by increasing the pH of the slurry by 1.0, thereby reducing the depth of the sparging tube immersion in the slurry. Chiyoda noted that high dissolved chloride concentrations can significantly suppress the pH in the absorber slurry, potentially reducing the SO_2 removal. This effect is due to the high ionic strength caused by the chloride concentration, which

negatively impacts the transport of hydrogen ions to the surface of the limestone particles. This H^+ ion transport is necessary for the limestone dissolution process. The CT-121 process is relatively unaffected by the chloride concentration. In a typical spray tower design it would be necessary to increase the dissolved alkalinity to maintain SO_2 removal. This requires more un-dissolved limestone to be present, increasing the limestone feed rate and potentially the scaling potential of the slurry.

Mitsubishi/Advatech Double Contact Flow Scrubber (DCFS)

Mitsubishi Heavy Industries (MHI) has been providing emissions control systems for power plants for more than 40 years. The DCFS is the current state-of-the art for the MHI FGD technology and has been installed on power generation plants for the last 30 years. The Double Contact Flow Scrubber (DCFS) design is currently offered by MHI under the name Advatech in the North American markets.

In low sulfur applications, flue gas enters the bottom of the absorber where the absorbent slurry is sprayed upward through large diameter (1.5”) nozzles creating a dense liquid-filled area. Slurry is supplied to a single spray header by multiple large recycle pumps. The flue gas contacts the slurry as it is sprayed out of the nozzle (co-current), and as the liquid falls back down towards the nozzles (counter-current). Therefore, the flue gas double contacts the limestone slurry. While the single tower design is mainly used for low sulfur applications up to 700 MW and 97% SO_2 removal, efficiencies in excess of 99% have been maintained in high sulfur applications using a single DCFS module. A process flow diagram for this single tower arrangement is on the left in Figure 2.

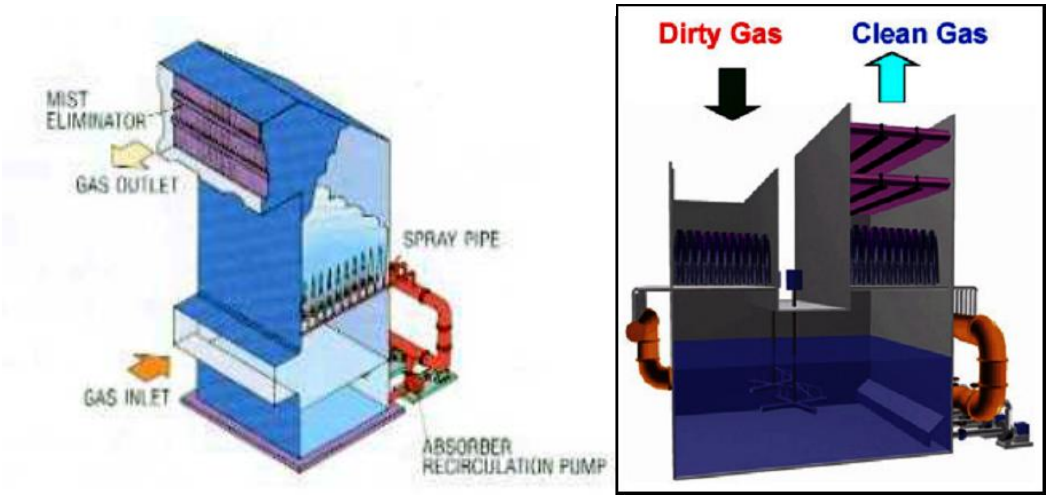
For larger units and those requiring higher removal efficiencies, as well as some higher sulfur fuel applications, MHI can add a second tower section so that the double-contact between the slurry and the flue gas occurs in two towers fed by a common reaction tank. The inlet tower is referred to as the co-current tower, and the outlet tower as the counter-current tower. A diagram of this dual tower application is shown on the right in Figure 2. The dual tower configuration has demonstrated removal efficiency capabilities of 99+%. One DCFS installation on a 2% oil-fired boiler has consistently been able to reach 99.9% SO_2 reduction.

One recent design enhancement for the MHI DCFS Process is the inclusion of a chemical oxygen demand (COD)/sulfite monitoring system that measures and controls the oxidation reduction potential (ORP) of the slurry. The ORP monitor maintains the slurry chemistry in the optimum range and indicates slurry conditions that could lead to aluminum fluoride blinding of the limestone particles in the slurry, allowing the operators to take action to stop the potential loss of reduction efficiency.

Medium sulfur fuel applications of the DCFS system have now demonstrated continuous operation at greater than 99% SO_2 removal efficiency. This commercial experience may translate to high efficiency commercial guarantees in the future. This level of performance can be achieved using either the single or twin tower design depending upon other operating

conditions at the plant. The DCFS design has achieved 99.9% efficiency with a single tower applied to a high inlet SO_2 flue gas stream (2,670 ppm on 150 MW unit). The outlet concentration was measured at 3 ppm. This performance is stated to be possible due to the enhanced liquid-to-gas contact and high reagent activity in the 30 wt.% slurry. Similar performance was obtained at a second unit operating on a 2,600 ppm gas stream (99.6% SO_2 reduction with design guarantee at 98.3% on 100 MW unit).

Figure 2: MHI/Advatech Single and Dual Tower DCFS Diagram



Alstom Open Spray Tower and FLOWPAC Scrubber

The open spray tower was Alstom's first FGD product offering with the first unit starting up in 1975. The absorbers generally have two or more spray levels, each with their own dedicated recycle pump. Design, selection and placement of spray nozzles at each spray level are critical to performance in high efficiency wet FGD systems. The spray nozzle configuration is determined by computer modeling in order to achieve the desired gas to liquid contact and scrubbing efficiency.

One of the innovations added to the original spray tower design are wall rings. Wall rings are radial baffles that project inward from the spray tower wall and redirect any flue gas traveling up the tower wall back into the spray zone. These baffles have been shown to improve SO_2 removal efficiency by 2-5% or alternatively to allow 10-20% reduction in liquid-to-gas ratio and achieve the same SO_2 removal as without baffles. Additional advances in spray tower design and operation include the following:

- Use of conservative design parameters in the areas of oxidation air stoichiometry and good air distribution has reduced the occurrence of oxidation deficiencies in the latest designs.

- Maintaining 18-20% gypsum solids in the recycle slurry provides more surface for crystal growth in the slurry than is available on the internal surfaces. This helps to reduce scaling on internal surfaces and increase system reliability. Nuclear density meters have demonstrated their ability to tightly control suspended solids density in the recycle slurry.

Alstom has guaranteed 98% removal for high efficiency applications. Several of Alstom's operating spray towers have achieved 99+% removal for extended periods, while others have been able to achieve 2-3 ppm without the addition of any organic acid. The Navajo installation has maintained an outlet emission rate of 0.04 lbs/MMBtu, which is approximately equivalent to 17 ppm SO_2.

Alstom is using their commercial spray tower design at these high performance installations, incorporating wall rings and slurry spray patterns to eliminate the potential for flue gas sneakage past the sprays. Trays or additives should not be required to achieve these high levels of continuous performance in the future. To maintain constant 99+% reduction, it will probably be necessary to add another spray level, and increase the L/G to the absorber by 20-25%.

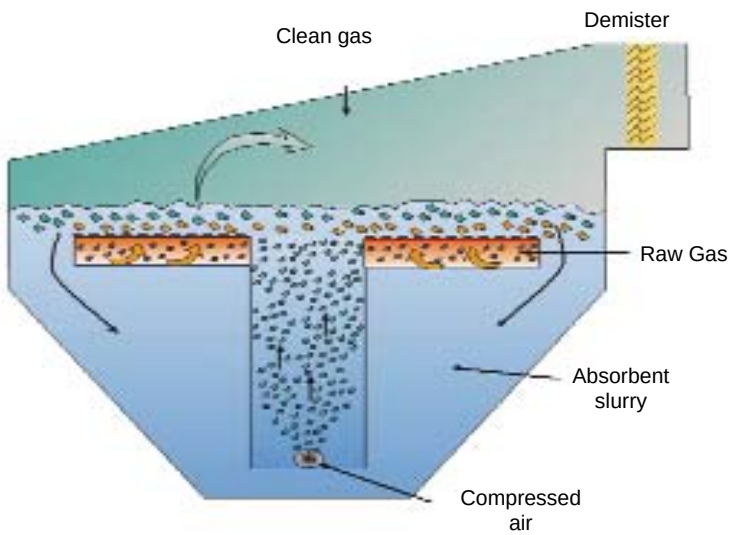
Alstom has recently developed a new scrubber design -- the FLOWPAC turbulent bed absorber. The chemical reactions occurring in the FLOWPAC absorber are essentially identical to those in all other LSFO systems. The primary difference between this process and standard open spray tower design is the unique absorber vessel used in the FLOWPAC system. Alstom has a full-scale commercial system operating at a 340 MW high sulfur oil-fired unit located at the Karlshamm power plant in Sweden. This full scale unit achieves 98% SO_2 removal continuously when firing a 3.5 weight % sulfur oil. It is also reported to have achieved 99.5% SO_2 removal when acetic acid is added to the slurry and the plant was burning 2.4% S fuel oil for a 3-month period.

The first FLOWPAC absorber consisted of an absorber tank with a circumferential sieve tray installed at the top of the tank. The flue gas enters the absorber beneath the sieve tray. Recycled slurry pours over the sieve tray, and the flue gas bubbles up through the slurry forming a highly turbulent froth layer. The froth layer provides a large surface area of reagent and flue gas. Slurry flows through return pipes downward from the outside of the sieve trays to the bottom of the absorber tank where oxidation air is introduced. The oxidation air acts as the lifting method recycling the slurry from the bottom to the top of the reaction tank, thereby eliminating the need for slurry recycle pumps. Figure 3 provides a flow diagram of the FLOWPAC process. Alstom is testing a rectangular tank design on a pilot scale at the Karlshamn plant.

The FLOWPAC absorber can change the depth of the bubble layer above the sieve tray to follow the plant load or changes in inlet SO_2 concentration. This ability to change the depth above the sieve tray also provides an inherent capability to achieve higher SO_2 reduction

efficiencies, with the 99+% capability already possible and previously demonstrated. This increase in slurry depth comes with a higher absorber pressure drop.

Figure 3: Alstom FLOWPAC Turbulent Bed Absorber



Alstom has recently begun to actively market the FLOWPAC absorber design around the world, and has introduced the concept to the U.S. utility market. To-date, there are no FLOWPAC installations or sales in the U.S. However, two have been sold overseas – one in Lithuania (3 x 150 MW) and one in Denmark (1 x 150 MW). These units are scheduled for startup in 2008 and 2009, respectively.

Babcock & Wilcox Wet Lime and Limestone Forced Oxidation Tray Tower

B&W has supplied FGD systems to the U.S. utility industry for decades. Their original focus was on the use of lime reagents in a tray tower design. Recent experience includes many installations of LSFO systems, again using a combination of trays and an open spray tower. B&W has also developed an oxidation systems for lime FGD systems, allowing the process to produce a gypsum product instead of a sulfite product that must be mixed with lime and flyash before disposal in a landfill. The typical B&W absorber uses a perforated tray and two absorber spray levels. The two spray levels include one under and one above the tray.

The hot flue gas enters the absorbers and is cooled to saturation by absorber slurry sprayed from the spray level under the tray, as well as the slurry falling from the tray. The saturated flue gas flows through the absorber tray, which distributes the flue gas and slurry from the upper spray level across the absorber cross-section. As the gas passes through the tray perforations the increased gas velocity generates energetic bubbling thereby assuring liquid-

gas contact. The flue gas then passes through the upper absorber spray zone, where absorber slurry spraying countercurrent to the flue gas flow completes sulfur dioxide removal.

- Tests conducted on a LSFO FGD system operating at a coal-fired power plant showed that addition of a second perforated tray and operation at a higher L/G ratio increased the SO_2 removal from 90% to 98% at slightly lower lime stoichiometry.
- In a second test at the same installation, addition of the second perforated tray and increasing the pH by 0.5 increased the SO_2 removal from 90% to 98%.

As previously mentioned, B&W's lime systems may warrant renewed interest, especially since magnesium enhanced lime (MEL) can achieve the same SO_2 removal efficiencies as LSFO systems, but at much lower L/G ratios. Based on medium sulfur Appalachian coal, the B&W LSFO system was able to achieve 98% removal at an L/G ratio of 130, whereas MEL was able to achieve 98% removal at an L/G ratio of 40. When using the lime reagent, further increases in the recycle rate could lead to a system capable of 99+% SO_2 reduction. There are 30 MEL installations in the U.S. ranging in size from 80 MW to 1400 MW. The new MEL oxidized process is used at seven of the units. This process allows for the SO_2 reaction products to be oxidized from calcium sulfite to calcium sulfate.

Babcock Power

Babcock Power relies primarily on an open spray tower design using bi-directional sprays (slurry sprays upward and downward with respect to the flue gas flow). The tower has wall baffles to mitigate the chance of internal flue gas bypass. The geometry of each spray level varies and the direction of the spray from the spray nozzles is also designed to mitigate the chance of internal flue gas bypass. This LSFO process has the same process chemistry as the other LSFO processes. The following are recent design modifications and/or enhancements to the Babcock Power wet FGD process technology:

- The absorber inlet is optimized to provide the best possible gas flow distribution – they no longer use a tangential gas inlet and the gas velocity through the scrubber has been increased by more than 20% to reduce the capital cost while improving the gas-liquid contact efficiency. This is offset by an increase in the pressure drop across the absorber.
- Babcock Power employs CFD modeling to optimize the design of their FGD absorbers. This modeling resulted in changes to the location of and the number of nozzles per spray levels in their current wet absorber designs. The nozzle design has also been optimized, using dual-direction nozzles that can spray both co-current and counter-current to the direction of the gas flow through the absorber vessel. These nozzles produce small droplets that increase the number of droplet collisions, producing additional spray pattern coverage. A staggered spray pattern is also used.
- Nozzles are installed along the walls of the absorber vessel to spray countercurrent to the gas flow and minimize the potential for gas sneakage (wall effects) past the spray pattern. High spray flows along the absorber walls help to increase overall collection

efficiency. Wall rings are also used to reduce the potential for gas slippage past the spray zones.

- Babcock Power also offers a dual loop design for very high efficiency or high sulfur applications while reducing the overall power consumption.

Babcock Power stated that in order to achieve the 99+% reduction efficiency, it is likely that it could be met by the addition of another spray level with its associated recycle pump. The L/G increase would correspond to the increase in pumping capacity. No internal packing, trays or additives should be necessary. Babcock is currently testing these design modifications to confirm single digit performance capability, to enable them to offer this level of performance commercially in the future.

Siemens-Wheelabrator

The Siemens-Wheelabrator (Siemens) FGD absorber design comes in various configurations, ranging from a typical open spray tower to the use of a sieve tray and spray headers. They have supplied systems based on lime and limestone reagents, and provided recent installations with performance guarantees up to 98% achieving outlet SO_2 emission rates of 20-25 ppm. Siemens did not provide any additional input regarding their future plans to meet the high efficiency FGD market at this time.

Alternate FGD Technologies

Other methods have been proposed to increase SO_2 reduction efficiency across the FGD system. Some of these options are discussed in the following material.

Dry Injection of Trona

O'Brien and Gere, using trona supplied by FMC and Solvay, offers the trona injection technology for both SO_2 and SO_3 removal from coal-fired flue gas. Although these dry injection systems are not necessarily capable of achieving the 99+% reduction efficiency targeted in this analysis, they could provide some trim to the SO_2 inlet concentrations entering the wet FGD systems, thereby reducing the load on the scrubber and possibly its outlet emissions concentration. Reduction rates of 40-90% have been demonstrated in previous tests, with the most economical reduction efficiency falling in a range of 50-60%. Recent advancements include the use of milled trona down to 15 micron particle size to improve reagent utilization rates, and injection at higher gas temperatures in front of the air preheater to provide the better performance.

Dynawave/ReverseJet Scrubber

Monsanto EnviroChem (now MECS) offers the Dynawave/Reverse Jet Scrubber technology for electric utility applications. This technology has seen most development and application for removal of SO_2 from sulfur recovery units (SRUs) operating in refineries, achieving 99.8% reductions. However, the inlet concentrations of SO_2 for these units are very high,

and the technology has not been applied to a coal-fired boiler in the U.S. to-date. Pilot testing has demonstrated the system's capability to achieve less than 6 ppm SO_2. The process relies on a reverse jet scrubber design; SO_2 is captured by contacting the flue gas stream with an alkaline reagent in a froth zone region of intense turbulence with substantial back-mixing and a high rate of liquid surface renewal. This froth zone is generated in an inlet duct to the absorber where slurry is injected into the gas pass counter-current to the gas flow. These fountains provide intimate gas-liquid contact. The momentum of the gas causes the liquid to spread out and form a standing wave at the point where the liquid and gas momentums are balanced. Turbulent films of liquid occlude and envelop the particulate or gaseous contaminants, while also providing the gas-liquid contacting necessary for gas quenching and acid gas absorption.

Until 1987, this technology was confidential and applied only within DuPont. In 1987, MECS realized the applicability of the froth scrubbing technology for FGD applications, and entered into a licensing agreement with DuPont. Since then, MECS has built more than 300 DynaWave® systems for various industries around the world.

Multi-Pollutant Systems

The following material provides brief descriptions of multi-pollutant processes that simultaneously remove SO_2, NOx, and mercury (Hg). These processes have the potential to remove high levels of SO_2 and consequently are included in this report. Some of the processes have commercial-scale experience overseas, but most are only at the demonstration stage. These processes are of interest because of the benefit of being able to remove several pollutants, but it may be difficult for utilities to justify selection of one of these processes until they gain more extensive commercial experience.

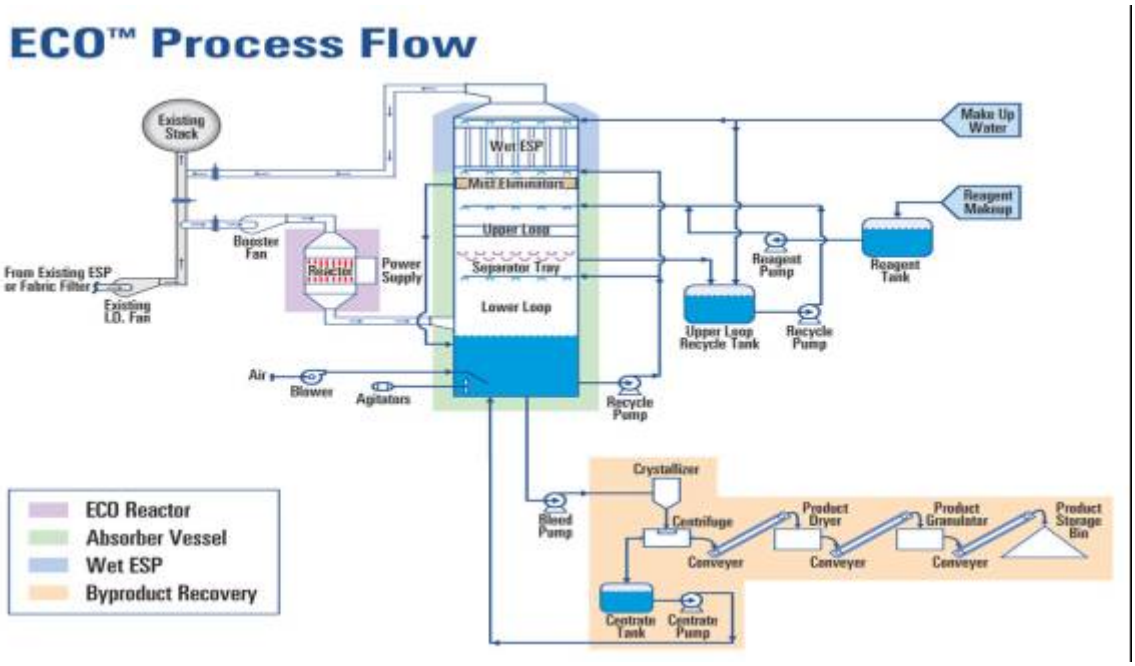
Powerspan ECO™ and ECO_2™

Powerspan's ECO™ process is designed for installation downstream of an existing particulate collection device. The process utilizes a dielectric barrier discharge reactor to oxidize pollutants in the flue gas stream, followed by a wet ammonia scrubber and wet ESP for removal of oxidized pollutants and byproducts. The technology produces a saleable ammonium sulfate fertilizer byproduct. A process flow diagram is shown in Figure 4.

The ECO™ technology was pilot tested on a 1-MW equivalent slipstream of FirstEnergy's R.E. Burger Plant in southern Ohio for four years and followed by the installation of a 50 MW commercial demonstration unit at the same site. Emission results from the pilot tests and the commercial scale demonstration have shown similar performance, achieving 98% SO_2 removal, 90% NOx removal, 85% Hg removal, and less than 0.01 lb/MMBtu emissions of fine particulate. Higher SO_2 reduction efficiencies appear to be possible given the results of short term testing. Powerspan has entered into agreements to construct additional full scale installations in Ohio and as part of an ECO_2 installation in North Dakota.

Since the possible need for power plants to capture CO_2 is one factor driving higher SO_2 removal efficiencies, it is worth mentioning Powerspan's ECO_2^{TM} Process, which is under development to absorb CO_2 from power plant flue gas. The ECO_2^{TM} process utilizes an aqueous solution of ammonia to absorb CO_2 from the flue gas. The system is designed to be installed downstream, and work in conjunction with, the ECO^{TM} technology. The CO_2 is later released for sequestration, while the ammonia is recycled back to the system to minimize operating costs.

Figure 4: ECO™ Process Flow Diagram



Powerspan and the DOE's National Energy Technology Laboratory (NETL) are working under a three-year cooperative research and development agreement (CRADA) to conduct tests on ECO_2^{TM}. Initial results indicate up to 90% CO_2 removal associated with the injection of aqua ammonia. Current plans are to eventually run a pilot test on a power plant near the end of the CRADA, at which point the process design and cost estimates will be finalized. Preliminary cost estimates predict that ECO_2^{TM} will cost less than half of the current CO_2 removal technologies that are commercially in use.

J-Power ReACT

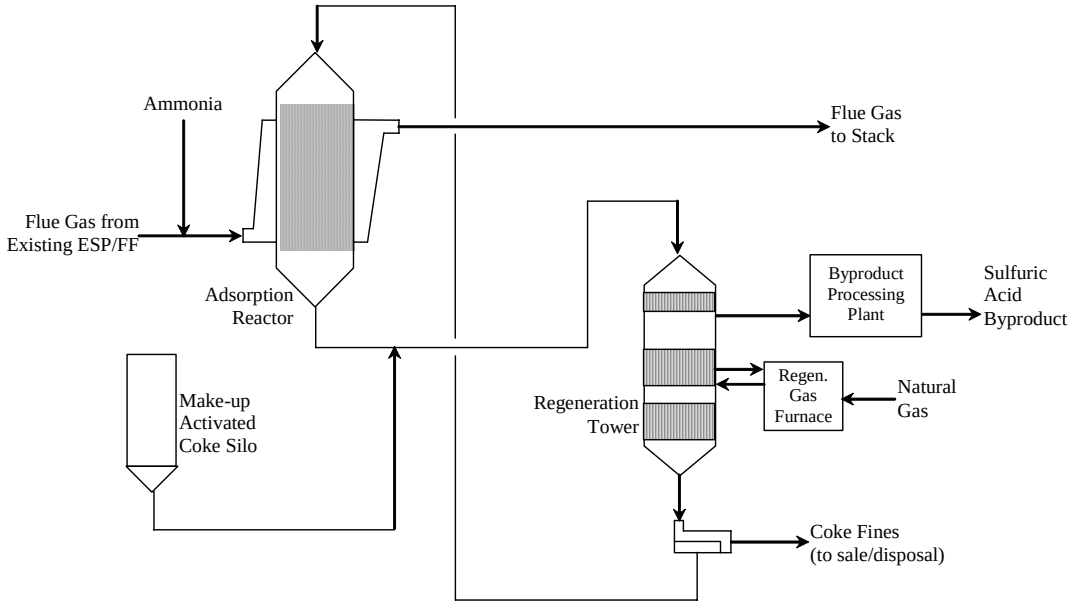
The ReACT process utilizes a moving bed of activated coke (AC) with ammonia injection to simultaneously remove SO_2, NOx, and mercury from the flue gas. Spent activated coke from the adsorption process is regenerated and recycled back to the adsorber, while SO_2 rich gas is sent to a byproduct recovery unit and processed into a saleable sulfuric acid or gypsum

byproduct. The ReACT system is currently being marketed worldwide by J-POWER EnTech Inc. J-Power, formerly known as Mitsui Electric Power Development Company, is a Japanese utility with 67 plants and 16,000 MW of capacity, approximately half of which is coal fired.

The activated coke process was initially developed in Germany and Japan by Bergbau Forschung (BF) and licensed to Mitsui Mining Company. J-POWER has recently acquired the patents for the Mitsui-BF process and established J-POWER EnTech Inc. to market ReACT worldwide.

The ReACT technology has been installed on 14 commercial units to date, including four coal-fired utility boilers and other industrial flue gas applications. All commercial installations of the technology are located abroad, with the majority located in Japan. The technology has been demonstrated successfully on large utility boilers, with a 350 MW installation in operation at J-Power's Takehara Unit #2 since 1995, and a 600 MW installation in operation at Isogo #1 since 2002. J-POWER is currently constructing another 600 MW unit at the same site, Isogo #2, scheduled for startup in July 2009. Figure 5 contains a simplified process flow diagram for the ReACT process.

Figure 5: ReACT Simplified Process Flow Diagram



Commercial installations located in Japan and Germany operate at 90-99% SO_2 removal, with SO_2 inlet concentrations as high as 1300 ppm SO_2. NOx removal at existing installations ranges from 50-80% on coal-fired units, but is highly dependant on coal sulfur content. Sulfur dioxide in the flue gas reacts readily with injected ammonia, limiting the amount of NOx removal that can occur at an injection rate that limits ammonia slip. J-

POWER EnTech reports ammonia injection into the regenerator is necessary if more than 50% NOx removal is required under higher SO_2 concentrations. However, recent findings indicate that NOx removal reactions from reducing compounds on the surface of activated carbon allow removal of >50% NOx for gas streams with higher SO_2 concentrations. Greater than 90% mercury removal has been demonstrated at the 600 MW Isogo #1 installation.

At this point, the ReACT technology has not been demonstrated on high-sulfur coal applications. To simulate U.S. flue gas conditions, J-POWER has performed slipstream testing at Isogo #1 with sulfur content up to 2,000 ppm. Performance tests were completed at various conditions in order to optimize the design. J-POWER EnTech expects that there will be some modifications to the system design to adapt to flue gas from Eastern U.S. coals. They recently completed a slipstream test of the ReACT system at a utility site in Nevada.

The ReACT technology is highly sensitive to coal sulfur content. The system was initially designed for low-sulfur (<1300 ppm) coals, and has not been optimized for operation with higher sulfur contents at this point. For high sulfur concentrations, the amount of activated coke fed to the adsorber increases substantially due to the need for more contact area to remove SO_2 from the flue gas. This results in the need for additional adsorber and regenerator modules, and supplementary solids conveying equipment. Additionally, the amount of sulfuric acid byproduct increases with the amount of SO_2 removed, resulting in increased sulfuric acid production plant costs. Demonstrated SO_2 removal efficiency has approached 99% in some low sulfur coal commercial installations.

Airborne

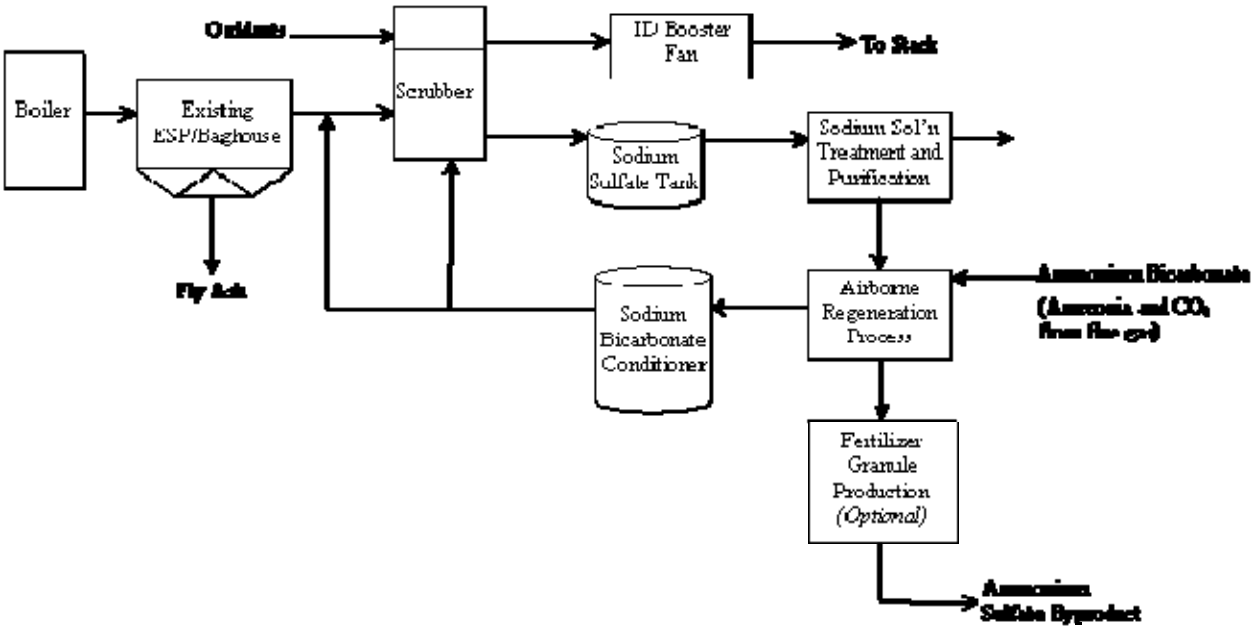
The Airborne Process™ uses a sodium bicarbonate scrubbing technology combined with post-scrubbing oxidants to remove sulfur dioxide (SO_2), sulfur trioxide (SO_3), nitrous oxide (NO_x), and mercury (Hg) from combustion flue gases, while producing a saleable fertilizer byproduct. Additionally, the process removes other heavy metals and toxics release inventory substances, such as sulfuric acid (H_2SO_4), hydrochloric acid (HCl), and hydrofluoric (HF) acid. A flow diagram of the process is provided in Figure 6.

Flue gas desulfurization using sodium carbonate or bicarbonate has been previously identified as a highly effective process; there are over 3,200 MW of sodium scrubbing experience that has been in operation for over 25 years. However, sodium reagent costs are often economically prohibitive, and the sodium sulfite byproduct can pose a disposal problem. Sodium scrubbing has been in operation at PacifiCorp's Jim Bridger Power Plant, Naughton Station in Wyoming, and at Nevada Power's Gardner Station. Sodium scrubbing at these units is made economical by use of a waste product sodium material from a manufacturing process in Wyoming.

Airborne Clean Energy (ACE) has developed a process where the sodium sulfite byproduct can be used to regenerate sodium bicarbonate reagent, while simultaneously producing an

agricultural grade fertilizer. ACE is offering this technology in combination with oxidants to achieve additional NOx and Hg removal.

Figure 6: Airborne Simplified Process Flow Diagram



The regeneration component of the Airborne Process™ was successfully demonstrated at Airborne's commercial sodium sulfate mine in Ormiston, Saskatchewan, Canada. The 18 ton/day demonstration plant was initially built with the intention of upgrading sodium sulfate to commercial-grade sodium bicarbonate for sale. The demonstration plant at Ormiston produced a 98%+ sodium bicarbonate product and 99%+ ammonium sulfate from a sodium sulfate feed stream. Both sodium bicarbonate and ammonium sulfate were sold from the pilot plant.

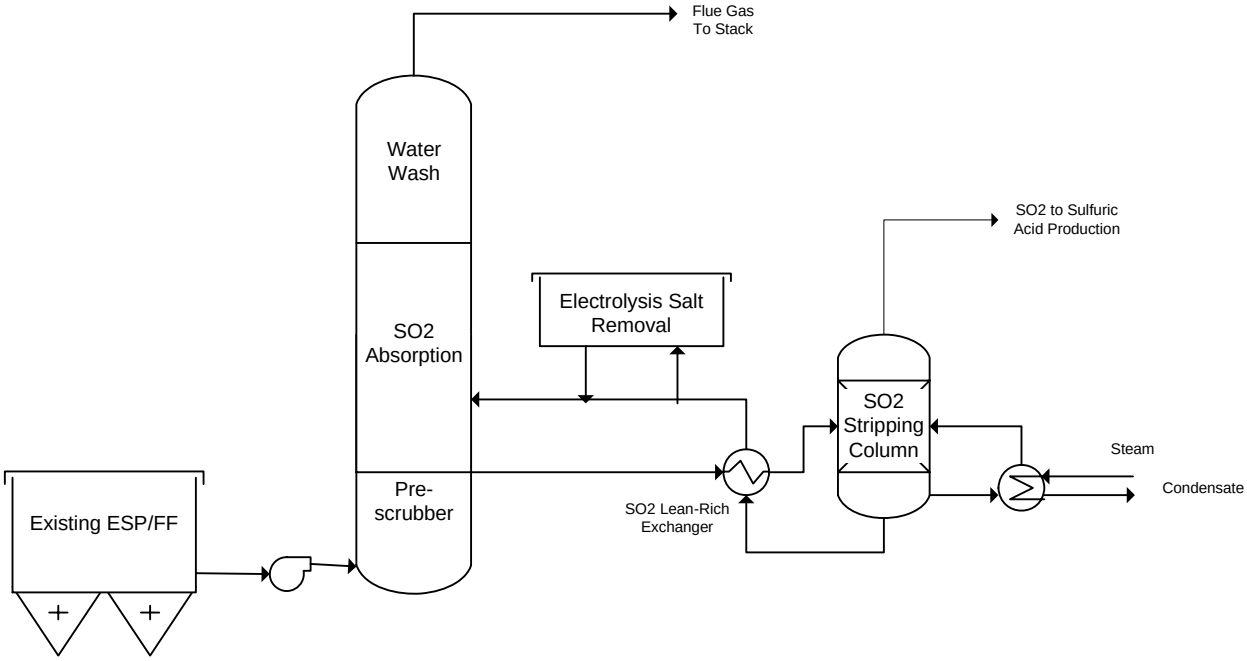
The first demonstration of the integrated technology was installed at LG&E's Ghent Generating Station located in Carroll County, Kentucky. As a part of the DOE's Clean Coal Power Initiative, the technology was installed on a 5 MW equivalent slipstream of Unit 2, and tested between January and July 2003. The tests demonstrated effective operation of the system including the reagent regeneration step. According to data provided by the vendor, the demonstration unit achieved 99.9% SO_2 removal on a consistent basis. NOx removal was approximately 40% during normal operation, and increased up to 90% removal with the addition of an oxidant. Additional NOx removal could be obtained by the reduction of sodium bicarbonate particle size. Mercury removal during operation of the demonstration facility peaked at 60-80% removal.

A commercial scale demonstration at the 300 MW Mustang Generating Station near Milan, NM was halted when Peabody Energy, HPD LLC was unable to secure an air permit from the New Mexico Government. ACE is installing their system at Saskatchewan Minerals and they are in negotiations with other clients in North America and China.

CANSOLV™ Process

The CANSOLV system expands on the regenerable amine SO_2 removal process by including CO_2 removal in an integrated tower configuration. NOx and Hg removal capabilities, previously marketed, have been discontinued from CANSOLV's product offerings. CANSOLV is focusing on marketing the SO_2 and CO_2 process configuration as shown in Figure 7. To better address the U.S. market, CANSOLV has teamed with Massey Energy and HG Engineering to form CANSOLV LLC to market their SO_2 and CO_2 process.

Figure 7: CANSOLV Simplified Process Flow Diagram



The CANSOLV System was initially developed as a SO_2 scrubbing technology for industrial gas streams. CANSOLV's SO_2 system is currently operational at seven different commercial installations, with two more scheduled for startup at the end of 2007. Of the nine installations, four are in the U.S., two in Canada, and the others overseas. All of the installations operating or under construction are either at smelters or petrochemical plants. The inlet SO_2 concentrations at these installations range from 800 ppmv to 11 volume % sulfur. The largest of these installations removes ~97% SO_2 from a fluid catalytic cracking unit (FCCU) unit flue gas stream equivalent to 175 MW. At an acid gas installation, SO_2 is

reduced from 3,000 ppmv to 15 ppmv in the outlet flue gas (99.5 % removal). Three of the installations have been operating since 2002 and four have been operating since 2005/2006.

CANSOLV's SO_2/NOx and CO_2 technologies were tested at pilot-scale at the Saskatchewan Power Poplar River station in 2006. These tests showed positive results for the CO_2 system, and less interesting results for the NOx and Hg process. As a result, CANSOLV has currently discontinued NOx control from its commercial offerings, but is actively pursuing CO_2 control. They were competing for a large-scale CO_2 capture system in Norway.

Other Developing Multi-Pollutant Processes

The following developing technologies are targeting 99% SO_2 removal efficiency or higher: ISCA, Lextran, Consummator, Green Coal, Envirolution, Flue-Ace, PEA, EnviroScrub, and the IPR system. All of these systems are proceeding through initial stages of commercial development.

COST IMPACTS

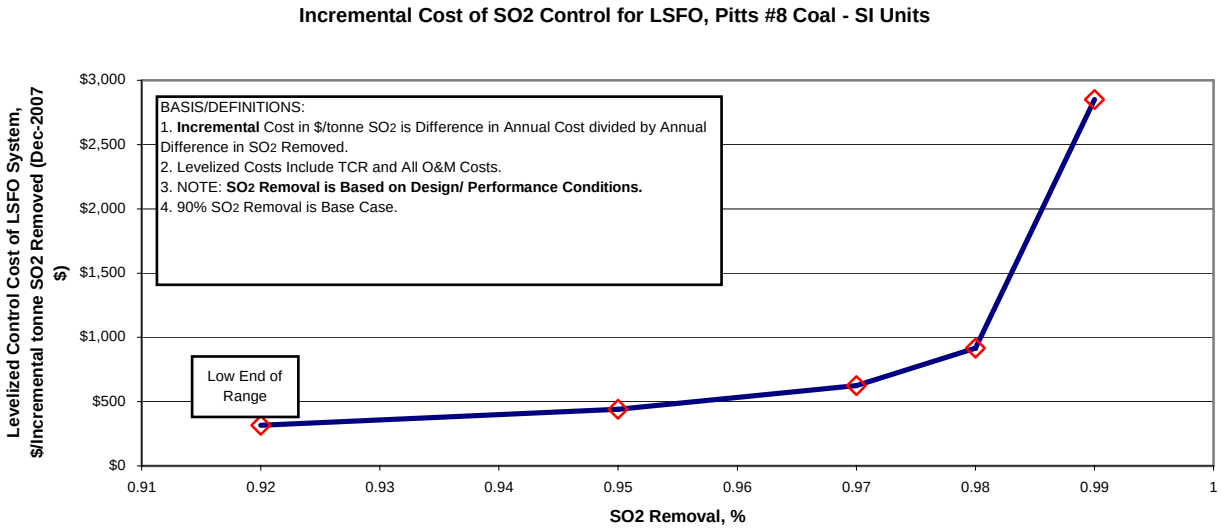
It should be noted that the cost estimates provided herein are termed rough-order-of-magnitude (ROM = ± 30% accuracy) and are dependent upon the various underlying assumptions, inclusions and exclusions utilized in developing them. Actual project costs will differ, and can be significantly affected by market pressures, other changes in the external environment, and the manner in which the project is implemented. Estimate accuracy ranges are only projections based upon cost estimating methods and are not a guarantee of actual project costs. The base case costs are generic and it should be understood that site-specific issues might result in wide variations in cost for these technologies.

Increased SO_2 Removal

An EPRI study completed in 2006 identified the incremental cost of SO_2 removal for one case based on the use of a wet limestone with forced oxidation FGD system (LSFO) in a spray tower absorber vessel. The system was installed on one 500 MW unit burning Appalachian coal (Pittsburgh # 8 coal with HHV of about 13,400 Btu/lb and 2.1 wt. % sulfur). Figure 8 provides the incremental cost of this LSFO case as the SO_2 removal increases from 90% to 99%.

From this figure, it is apparent that the incremental cost increases moderately from 92% to 97%, and dramatically rises from 97% to 99%. To achieve these removal rates, the L/G ratio was increased for each percentage point increase in SO_2 removal in this scenario. The impacts of increasing the L/G ratio include the following: need to purchase larger absorber circulation piping, more spray nozzles, larger and/or additional absorber circulation pumps, and an increase in the flue gas-side pressure drop resulting in increased ID fan power consumption, and repositioning of the spray header to accommodate the new spry pattern at the increased flow rates.

Figure 8: Incremental Cost of Increasing SO2 Control



Incremental Cost Impact of SO_2 and CO_2 Removal for Increasing FGD Removal Efficiency

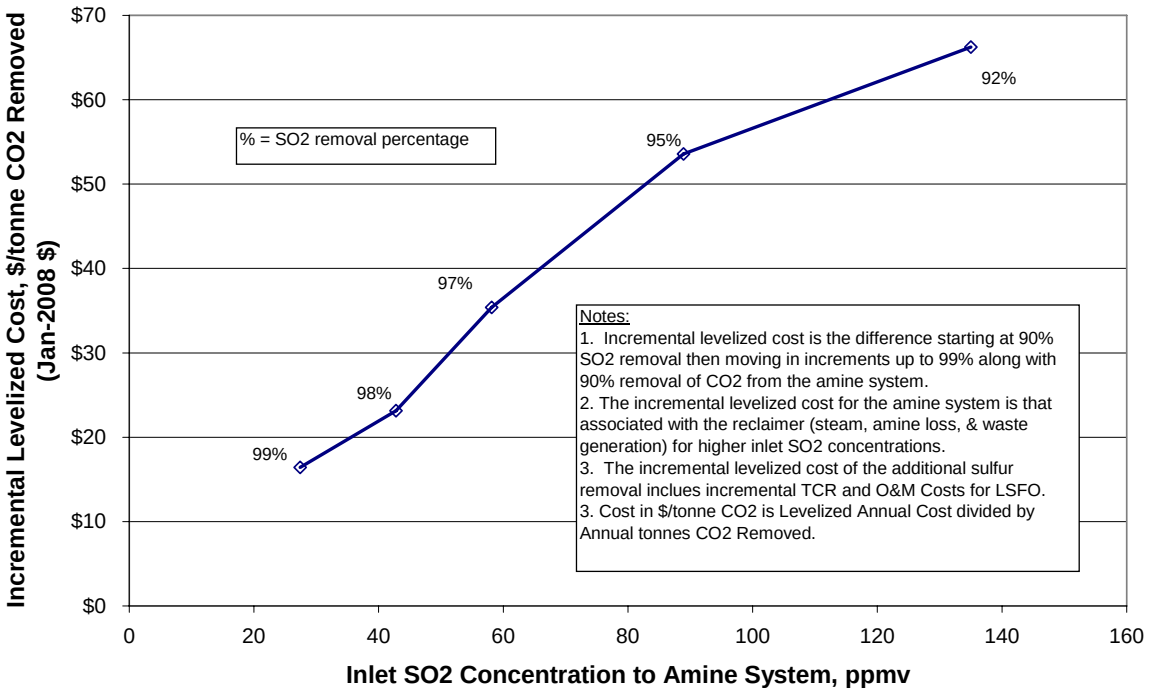
Although the bulk of this paper covers high efficiency SO_2 removal, the looming possibility of regulations requiring fossil fuel-fired power plants to reduce CO_2 emissions is relevant to the discussion. Some CO_2 removal processes will directly impact the design and performance required from any FGD system operating upstream due to the low inlet SO_2 concentration sometimes required by the CO_2 reduction system. In many cases, sulfur dioxide needs to be in the low ppm range so that the CO_2 removal processes can be a cost-effective candidate for installation at a PC-fired power plant. An amine based system, which is widely used in the gas processing industry to remove CO_2 from gas streams, is one available technology option for PC fired utilities to capture CO_2 from their flue gas streams. Amine based systems require very low inlet SO_2 concentrations, mainly to minimize the buildup of heat stable salts in the amine scrubbing loop. A thermal reclaimer is commonly included with an amine scrubbing system to remove these heat stable salts. This regeneration step requires energy, produces a waste product, and results in an increase in the amine degradation/makeup rate.

An analysis was performed to examine the levelized cost for a PC power plant firing an Appalachian coal (2.6 wt% sulfur) with a LSFO FGD step and CO_2 removal using an MEA (monoethanolamine) system. The plant size was assumed to be 500 MW, gross, excluding the power requirement for CO_2 and SO_2 removal systems. The levelized costs are presented in dollars per tonne of CO_2 removed.

The analysis examined the incremental cost for removing additional SO_2 in increments from 90% to 99% for the LSFO process. This included the incremental capital and operating costs associated with the FGD system at various control efficiencies, as well as the incremental operating costs for the amine scrubbing system as they related to variations in the inlet SO_2 concentrations. These costs are primarily related to the operation of the thermal reclaimer including variations in steam usage, amine losses, and waste generation rates. All of these operating costs typically increase as the inlet SO_2 concentration increases.

The correlations for the increase in MEA consumption and increased reclaimer duty were taken from Simisky (1986). The cost for makeup of the MEA was assumed to be $2.11/lb. The steam cost was assumed to be $3.86/1000 lb and the amine waste disposal cost was based on $0.19/gallon. The results shown in Figure 9 demonstrate the impact that SO_2 inlet concentration has on the incremental levelized cost for the sum of the FGD and CO_2 removal systems. It should be noted that the analysis in Figure 9 does not include capital costs for the CO_2 capture process nor does it include capital and operating costs for CO_2 sequestration.

Figure 9: Incremental Cost of SO_2 Control for LSFO Plus Incremental Amine System Cost for CO_2 Removal Based on Amine Inlet SO_2, Appalachian Coal (2.6 wt% S)



It is clear that the lowest inlet SO_2 concentration to the amine unit will result in the lowest additional cost for CO_2 removal. The cost for amine losses is the largest contributor to the increase in levelized cost, followed by the additional energy cost associated with the steam requirement for thermal regeneration. Although the inlet SO_2 concentration for the bituminous case is above single digit ppm levels, the evaluation emphasizes the need for FGD technologies to be able to maintain 99+% SO_2 removal for the sake of operating a downstream CO_2 removal system.

SUMMARY

In the foreseeable future it is possible that electric utilities may be required to reduce their SO_2 emissions by 99+% due to the current regulatory environment and public pressure on regulatory agencies to control CO_2 emissions in the future. Many of the major FGD suppliers in the U.S. have demonstrated SO_2 removal efficiencies in the 98% - 99% range with only limited modifications to their absorber design and operating conditions. Several of the design modifications that the FGD vendors are employing to achieve these results include: installation of wall baffles or rings; addition of trays and spray levels; use of CFD modeling to improve the inlet gas distribution, spray nozzle configuration and slurry spray patterns to improve gas to liquid contact and limit the amount of gas sneakage. In a number of cases it may be necessary to use spare recirculation pumps and spray headers to increase liquid to gas (L/G) slurry recycle ratios by 20-30% to achieve increased SO_2 removal. Other FGD absorber designs rely on adjusting some other operating characteristics such as increases in pH, increasing the froth layer contact depth, use of chemical additives, improved monitoring of process operating conditions, etc. To consistently maintain 99+% SO_2 removal on a multi-day rolling average basis, greater emphasis will need to be placed on monitoring and maintaining FGD performance. This may require the utility industry to consider adopting a different operating philosophy; one that includes more hands-on involvement of engineering staff day-to-day and greater attention to instrument and equipment maintenance.

Increased SO_2 removal does not come without a cost. The incremental cost per ton of SO_2 removed above 98% is exponential for a traditional LSFO system. If regulation of CO_2 emissions is enacted, then not removing enough SO_2 will only add to a utility's operating costs. An amine based CO_2 removal process, one of the few commercially proven and available CO_2 removal processes at present, is more cost effective at lower inlet SO_2 concentrations due to the negative impact that SO_2 has on the operational chemistry of the process.

Some of the latest process developments in the area of multi-pollutant control technologies may result in cost-effective alternatives that achieve high SO_2 removal in conjunction with removal of NOx and mercury. Multi-pollutant technologies such as ECO™, ReACT, Airborne, and CANSOLV™ show promise of achieving 99+% SO_2 removal and continue to gain commercial experience, improve performance, and achieve higher reliability. As

federal, state and local agencies demand additional reduction in SO_2, NOx and mercury emissions, these integrated emission control systems may see more consideration due to operating advantages and cost competitive performance when compared to installation of separate control systems for each of the respective pollutants.

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