

# Technical Paper

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## *Advanced Emissions Control Technologies for Coal-Fired Power Plants*

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*Power-Gen Asia*

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## Introduction

Coal is one of the most abundant energy sources in the world. Advanced emission control technologies are needed to cleanly use coal for electricity generation. Environmental regulations of coal-fired power plants in Asia cover a broad range of requirements. Depending on the area within Asia and the type of coal to be burned, different combinations of technologies are needed to meet local regulations. There are a multitude of advanced emissions control technologies available to address the most common targeted pollutants such as sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), and particulate matter (PM), as well as other pollutants which are increasingly becoming targeted worldwide, such as mercury, sulfur trioxide (SO<sub>3</sub>), condensable PM, and other trace metals. This paper examines state-of-the-art emissions control systems that are available to meet the multi-pollutant requirements for coal-fired power plants. These technologies include selective catalytic reduction (SCR), electrostatic precipitators (ESP), fabric filters, flue gas desulfurization (FGD), wet ESP, dry sorbent injection, and mercury control methods.

## Asia Environmental Trends

The demand for power in Asia is increasing at a rapid rate. As a result, the need for high removal efficiency technologies for NO<sub>x</sub>, SO<sub>2</sub>, sulfuric acid mist, mercury, and particulate (PM<sub>2.5</sub>) is becoming more and more relevant to Asia. The need for environmental protection systems in Asia varies based on the growth of coal-fired power generation and environmental regulatory practices in each country. New environmental protection systems for electric utilities are tied to two (2) major categories:

1. New coal plants – Environmental protection systems installed as part of new coal plants as required by national environmental regulations for new plants or by rules imposed by certain development financing sources.
2. Retrofit of existing plants – Environmental protection systems installed on existing pulverized coal-fired boilers to meet lower emissions regulations.

Environmental protection technology has been extensively implemented in the power generation markets of Japan, South Korea and Taiwan for many years. Existing coal fired plants are generally equipped with state-of-the-art technology for reduction of traditional pollutants such as SO<sub>x</sub>, NO<sub>x</sub> and particulate. New environmental protection systems for these markets will primarily be for new coal fired power plants, but evolving regulations may lead to further upgrading of existing emissions control systems to meet lower limits.

China has more recently, over the past 10 years, implemented an extensive program to install flue gas desulfurization equipment on existing utility power plants. Additionally, all new power plants have been equipped with flue gas desulfurization and SCR NO<sub>x</sub> emission reduction systems as well as traditional electrostatic precipitator (ESP) particulate control equipment. In 2011, new regulations were established in China which set very low emission limits comparable to regulations in the United States (U.S.) and Europe for SO<sub>2</sub>, NO<sub>x</sub> and particulate for coal plants. These limits must now be complied with on all new plants constructed and all existing plants must be in compliance by July 2014. These new regulations also set objectives for measuring mercury emissions in preparation for future controls.

In most other countries in Asia, desulfurization, NO<sub>x</sub> and particulate control systems have been typically supplied as

part of new boiler installations. FGD additions on existing boilers has been limited to only a few countries, but may begin to be required by some countries that have significant un-controlled capacity such as Vietnam, Indonesia, India and the Philippines, in the next 5 to 10 years. Growing international and domestic pressures are likely to lead to some increased level of retrofit projects, but the majority of new near-term environmental systems will be part of the equipment train that is installed with new power plants.

In addition to the evolving emissions regulations in Asia, environmental protection technologies need to be adapted to a wide variety of coal types. Coals burned in Asia are both indigenous and imported from locations such as Australia and South Africa. Plants are designed to burn traditional lower-sulfur content bituminous coals, but many are being designed for lignite sub-bituminous and anthracite coals. Sulfur contents reflect a wide range as well from less than 0.5% to more than 4% by weight. Ash, moisture and volatile matter contents also vary widely, affecting the design and selection of environmental protection systems. As a result of both the evolving and varying regulatory emission limits and the wide variety of coal types being used in Asia, a variety of state-of-the-art emissions control systems will be needed to meet the multi-pollutant requirements for coal-fired power plants.

## Pollutants from the Combustion of Coal

Raw coal contains carbon (C), nitrogen (N), sulfur (S), ash, trace amounts of mercury (Hg) and other elements. Once these elements go through a combustion process with air, pollutants such as NO<sub>x</sub>, SO<sub>2</sub> and SO<sub>3</sub> are formed. See Table 1.

NO<sub>x</sub> refers to the cumulative emissions of nitric oxide (NO), nitrogen dioxide (NO<sub>2</sub>) and trace quantities of other nitrogen species generated during combustion. Combustion of any fossil fuel generates some level of NO<sub>x</sub> due to high temperatures and the availability of oxygen and nitrogen from both the air and fuel. N<sub>2</sub> and O<sub>2</sub> present in the air combine to form NO and NO<sub>2</sub> at high temperatures. The quantity of NO<sub>x</sub> formed during combustion depends on the quantity of nitrogen and oxygen available, the temperature, the intensity of mixing and the time for reaction.

When a sulfur-containing fuel is fired in a combustor, the sulfur in the fuel combines with oxygen and forms gaseous SO<sub>2</sub>. Some of the SO<sub>2</sub> produced is oxidized to SO<sub>3</sub>. SO<sub>3</sub> forms in two areas of a fossil fuel-fired power plant: the boiler and across the catalyst on units utilizing SCR for NO<sub>x</sub> reduction. Furnace geometry (surface area), oxygen concentration (excess air), fuel vanadium levels, fuel sulfur levels and ash composition all have an effect on the boiler conversion rate.

Particulates are very small diameter solids or liquids that remain suspended in the flue gas and which, without a collection device, are discharged to the atmosphere. The solids are typically made up of non-combustible ash or partially combusted soot. Fine particulate can also be formed by chemical reactions in the air.

**Table 1**  
**Formation of Pollutants from Coal Combustion**

Raw Coal Constituent	Combustion Result	Required Equipment
Carbon (C)	Heat, Steam, CO <sub>2</sub>	Boilers
Nitrogen (N)	NO <sub>x</sub>	Burners and SCR Systems
Sulfur (S)	SO <sub>2</sub>	Wet and Dry FGD
	SO <sub>3</sub>	Sorbent Injection, Wet ESP
Ash	Ash	Ash Handling, Sootblowers, Precipitators, Fabric Filters
Mercury (Hg)	Hg <sup>++</sup> , Hg <sup>0</sup>	Coal Additive, PAC Injection, Wet FGD Enhancement Systems

Mercury, present in only trace amounts in coal, is released during the coal combustion process, and can appear in several forms in the flue gas. In the solid phase, it is referred to as particulate mercury, and in the gaseous phase, it is referred to as vapor-phase mercury. The concentration of mercury in the coal is primarily dependant on the coal type. In the U.S., bituminous and lignite coals have the highest concentration of mercury, while subbituminous coal contains a lower concentration. However, mercury content is a function of geological formation and world-wide, the content of mercury by coal rank may vary from trends seen in U.S. coals.

Vapor-phase mercury, appearing in coal combustion flue gas, will be present as either elemental mercury or oxidized mercury, with proportions largely dependent on the type of coal being burned. It has been recognized by industry experts that there is a loose empirical positive relationship between the chloride content of coal and the extent to which its inherent mercury oxidizes. Therefore, a higher percentage of oxidized mercury is produced from high-chloride coal, such as eastern U.S. bituminous coals. For low-chloride coal, such as U.S. subbituminous and lignite coals, a higher percentage of elemental mercury is produced.

## NO<sub>x</sub> Control

The most detrimental effect comes from NO<sub>2</sub> which forms from the reaction of NO and oxygen. Once in the atmosphere, the NO<sub>2</sub> is involved in a series of reactions that form secondary pollutants. The NO<sub>2</sub> can react with sunlight and hydrocarbon radicals to produce ground level ozone/photochemical (urban) smog, acid rain constituents, and particulate matter. NO<sub>2</sub> also absorbs the full spectrum of light and can reduce visibility. NO<sub>x</sub> is associated with respiratory disorders, corrosion of materials and damage to vegetation. Excess NO<sub>x</sub> concentrations in the air result in a brownish color.

Techniques to control fuel-air mixing rates and optimize combustion temperatures are effective in reducing NO<sub>x</sub> emissions. NO<sub>x</sub> emissions may also be controlled through

careful fuel selection and selective fuel switching. Once a fuel is chosen, the next step is to minimize NO<sub>x</sub> emissions through the use of low NO<sub>x</sub> combustion technology. Combustion system NO<sub>x</sub> control is typically the lowest cost approach to reduce NO<sub>x</sub>, but may not be enough to meet required emissions. Figure 1 shows the Babcock & Wilcox Power Generation Group, Inc. (B&W PGG) AireJet® low NO<sub>x</sub> burner.

The final step is to use post-combustion NO<sub>x</sub> control such as selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) systems if the targeted NO<sub>x</sub> removal cannot be achieved. In either technology, NO<sub>x</sub> is reduced to nitrogen (N<sub>2</sub>) and water (H<sub>2</sub>O) through a series of reactions with a chemical reagent injected into the flue gas.

The most common chemical agents used in commercial applications are ammonia and urea [(NH<sub>2</sub>)<sub>2</sub>CO] for SNCR. Reagents commonly used for SCR are anhydrous, aqueous ammonia (19 to 28% concentration) and urea. When urea is used for SCR, it is typically decomposed on site to ammonia, carbon dioxide (CO<sub>2</sub>) and water. Regardless of the source, once the ammonia is in vapor form, it is common to dilute the ammonia stream with air to assist with transport, flow control and injection functions. Most ammonia-based systems have used anhydrous ammonia (NH<sub>3</sub>) as the reducing agent. However, due to the hazards of storing and handling NH<sub>3</sub>, many systems use aqueous ammonia. Urea can be stored as a solid or mixed with water and stored in solution.

SNCR technologies inject the reagent into a specific temperature zone. To initiate the reaction, it is important to properly mix the reagent with the flue gas, and the mixture must have adequate residence time at the required temperature. The acceptable temperature range for the reaction is 760 to 1100C (1400 to 2012F), although temperatures above 925C (1697F) are preferred. Below 870C (1598F), chemical enhancers, such as hydrogen, are needed to assist the reactions. As the temperature increases within this range, the ammonia or urea may react with available oxygen to form NO<sub>x</sub>. This reaction becomes significant at temperatures above 1100C (2012F) and may become dominant as temperatures approach 1200C (2192F). Typical NO<sub>x</sub> removal



**Fig. 1** AirJet® low NO<sub>x</sub> burner.

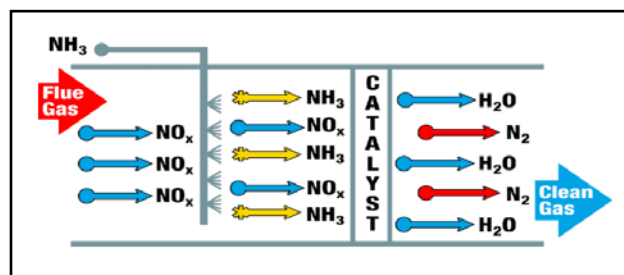
with SNCR ranges from 15 to 35%. NO<sub>x</sub> removal can be pushed up to approximately 50% but with high ammonia slip, which can have undesirable consequences.

When high NO<sub>x</sub> removals are required, SCR technology is needed. SCR systems catalytically reduce flue gas NO<sub>x</sub> to N<sub>2</sub> and H<sub>2</sub>O. This technology is the most effective method of reducing NO<sub>x</sub> emissions especially where high removal efficiencies (70 to 90%) are required. The NO<sub>x</sub> reduction takes place as the flue gas passes through a catalyst chamber. Before entering the catalyst, ammonia is injected into the flue gas where it is mixed. Once the mixture enters the catalyst, the reactions occur. See Figure 2.

The SCR reactions take place within an optimal temperature range. Most catalysts can operate in the range of 230 to 450C (446 to 842F) but optimum performance occurs between 360 to 450C (680 and 842F). The minimum temperature varies and is based on fuel, flue gas specifications and catalytic formulation. In addition, the minimum temperature tends to increase with flue gas SO<sub>2</sub> concentration because ammonium bisulfate formed when ammonia is injected into high sulfur content flue gas precipitates out of the gas at lower temperatures and fouls the catalyst. Typical NO<sub>x</sub> removal with SCR ranges from 50 to 90%. NO<sub>x</sub> removal can approach approximately 93%, but requires a tightly controlled inlet ammonia-to-NO<sub>x</sub> distribution. See Figure 3 for a typical coal-fired SCR installation.

## Particulate Control

Solid and liquid matter of organic or inorganic composition, suspended in flue gas or in the atmosphere is generally referred to as particulate. Particle size from combustion sources are usually found between 1 to 100 microns, although particles smaller than 1 micron can occur through condensation processes. These fine particles are formed in the atmosphere when gases such as SO<sub>2</sub>, NO<sub>x</sub>, and volatile organic compounds (VOCs), emitted by combustion processes, are transformed into fine particulate by chemical reactions in the air (i.e., sulfuric acid, nitric acid and photochemical smog). Particulate matter is often classified as PM<sub>2.5</sub> and PM<sub>10</sub>. PM<sub>2.5</sub> is particulate matter 2.5 microns and smaller. PM<sub>10</sub> is particulate matter 10 microns and smaller and it includes PM<sub>2.5</sub>. PM<sub>2.5</sub> is considered to have more detrimental health effects than the coarser particles. Among the effects of particulate emissions are impaired visibility such



**Fig. 2** NO<sub>x</sub> reduction process in an SCR.





**Fig. 3** 675 MW coal-fired SCR system.

as smog and haze, soiling of surrounding areas, aggravation of the adverse effects of  $\text{SO}_2$ , impaired plant growth and human respiratory problems.

Particulate control equipment is designed to remove the particulate from the flue gas stream, prevent the particulate from reentering the flue gas, and discharge the collected material. There are several types of particulate removal equipment including electrostatic precipitators (ESP), fabric filters, mechanical collectors and venturi scrubbers. Each uses a different collection process with different factors affecting the collection performance. For new units that need to meet stringent requirements, the selection is typically limited to ESP and fabric filters to meet high efficiency and high reliability requirements.

An ESP electrically charges the ash particles in the flue gas stream to collect and remove the particulate. The unit is comprised of a series of parallel vertical plates through which the flue gas passes. Centered between the plates are charging electrodes which provide the electric field. See Figure 4.

Operating collection efficiencies which exceed 99.9% are common for medium and higher ash coals with outlet emissions levels of approximately 12 to 36  $\text{mg}/\text{Nm}^3$  at 6%  $\text{O}_2$  (0.01 to 0.03  $\text{lb}/106$  Btu heat input) common on most coals. The resistivity of the ash plays a significant role in ESP design. ESPs are also widely installed on utility boilers that fire oil as their principal fuel. The advantages of a well-designed ESP are high total collection efficiency, high reliability, low flue gas pressure loss, resistance to moisture and temperature upsets, and low maintenance.

A fabric filter collects the dry particulate matter as the flue gas passes through the filter material. The fabric filter is comprised of a multiple compartment enclosure, with each compartment containing up to over a thousand long, vertically supported, small diameter fabric bags. The flue gas passes through the porous bag material which separates the particulate from the flue gas. See Figure 5.

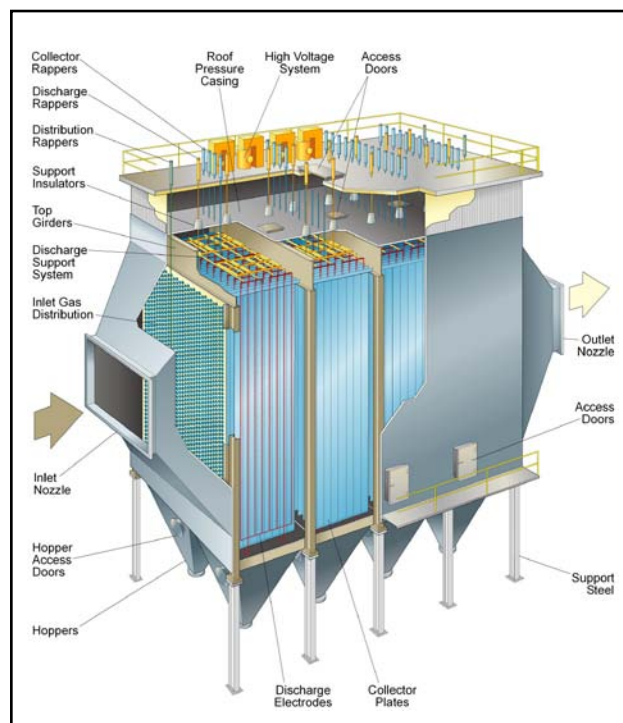
Well-designed filters routinely achieve greater than 99.9% particulate removal, meeting all current U.S. Environmental Protection Agency (EPA) and local regulations.

Besides standard utility pulverized coal-fired applications, fabric filters are used on circulating fluidized-bed boilers, industrial pulverized and stoker-fired coal units, and refuse-fired units in combination with a dry FGD. Fabric filters are not currently used on oil-fired boilers due to the sticky nature of ash.

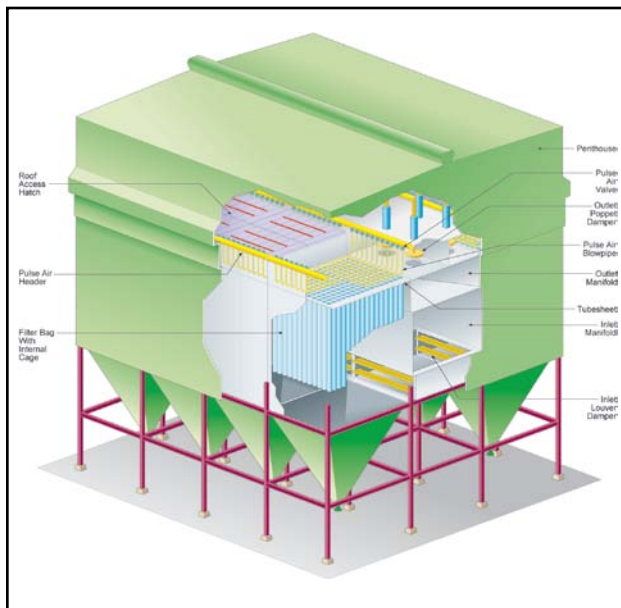
Fabric filters operate by passing flue gas through a felted or woven fabric. The particulate in the flue gas is deposited on the fabric surface as the dust-laden gas passes through the filter bag. The dust cake which forms on the fabric from the collected particulate contributes significantly to collection efficiency. A highly alkaline dust cake can be used to remove additional flue gas constituents and acid gases, such as  $\text{SO}_2$ . Because of this dust cake mechanism, fabric filters can also be used to improve the effectiveness of activated carbon additives which can be injected into the flue gas to control mercury emissions. Fabric filters generally are better collectors of the carbon and mercury components than are ESPs and provide a means for extended contact between the flue gas and the carbon.

There are two types of fabric filters for utility applications: reverse air and pulse-jet. Today, the pulse-jet type is typically chosen over the reverse air type because a pulse-jet fabric filter is smaller in size and lower cost. In a pulse-jet fabric filter, cake forms on the outside of the bags and is removed by a reverse pulse of high pressure air. This cleaning is accomplished with the compartment online, unlike a reverse air application where the compartment needs to be taken out of service.

Advantages of a fabric filter (with proper bag material selection) include high collection efficiency throughout the particle size range, high reliability, resistance to flow upsets,



**Fig. 4** Electrostatic precipitator.



**Fig. 5** Pulse jet fabric filter.

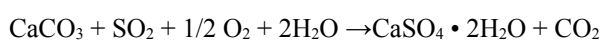
little impact of ash chemical constituents on performance, and good dust cake characteristics for integration with dry acid gas removal systems.

## SO<sub>2</sub> Control

SO<sub>2</sub> is an eye, nose and throat irritant that is associated with respiratory illness. One of the major effects of SO<sub>2</sub> emissions is acid rain. There are two basic approaches to controlling SO<sub>2</sub> emissions. These approaches reduce the sulfur in the fuel either through 1) fuel blending or fuel switching to a lower sulfur coal, or 2) utilizing a technology to remove the SO<sub>2</sub> from the flue gas.

A variety of SO<sub>2</sub> removal technologies are available. These include wet FGD, dry FGD utilizing a spray dryer absorber (SDA), circulating dry scrubber (CDS), and dry sorbent injection (DSI).

Wet FGD is the predominate technology used worldwide for the control of SO<sub>2</sub> from utility power plants. Limestone is commonly used as the reagent for wet FGD. For most high sulfur applications, a limestone wet FGD has an overall lower cost than other processes for SO<sub>2</sub> removal. However, wet FGD systems can be designed for a variety of reagents including lime, magnesium-enriched lime, seawater and soda ash. Limestone-based systems can also use an organic acid additive to enhance SO<sub>2</sub> removal. Additionally, wet FGDs have been successfully used for a complete range of coal types including anthracite, bituminous, sub-bituminous, lignite and brown coals. Wet FGD is also installed on systems that use heavy oil and Orimulsion for fuel. Conventional wet FGD systems utilize a wet limestone process with in situ forced oxidation to remove SO<sub>2</sub> and produce a gypsum byproduct. The overall reaction is:



The SO<sub>2</sub> removal process begins as hot flue gas enters the absorber tower where it is cooled and saturated by the slurry. The flue gas then flows upward through the absorber spray zone, where slurry is sprayed countercurrent to the flue gas flow, completing the SO<sub>2</sub> removal process. Typically, the SO<sub>2</sub> removal process includes an in situ forced oxidation system which converts calcium sulfite ( $\text{CaSO}_3 \cdot \frac{1}{2}\text{H}_2\text{O}$ ) formed by the SO<sub>2</sub> removal process to calcium sulfate ( $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ ) or gypsum. Limestone forced oxidation systems have achieved SO<sub>2</sub> removal efficiencies as high as approximately 98% in a variety of power plants firing a variety of fuels depending upon specific conditions of the application. See Figure 6 for a typical wet FGD system.

Dry FGD, is an alternative to wet FGD for SO<sub>2</sub> control on utility boilers. The process is also called semi-dry to distinguish it from injection of a dry solid reagent into the flue gas. An SDA is an example of this type of FGD system. In an SDA system, lime slurry (typical), is atomized and sprayed into the hot flue gas to absorb the SO<sub>2</sub> and other acid gases. The resulting dry material, which includes reaction products and flyash, is collected in a downstream particulate control device, typically a fabric filter or sometimes an ESP. A portion of the dry material is recycled back into the lime slurry mixture as a means to minimize lime usage by taking advantage of the alkalinity in the ash.

An advantage of SDA technology compared to conventional wet FGD technology is that the SDA system locates the fabric filter, which is a very efficient dust collector, as the last environmental system component in the flue gas cleaning train before the stack. The SDA cools the flue gas to about 65 to 75C (149 to 167F) before the gas passes through the fabric filter. As a result, any metals which have a vapor pressure at flue gas temperature tend to be present more in the solid state and are easier to capture in the fabric filter.



**Fig. 6** Typical wet FGD system.



Extremely low particulate emissions are thus possible, including  $PM_{2.5}$ , provided the fabric filter is properly designed and the correct bag material is selected.  $SO_2$  removal of up to approximately 96% can be achieved with this technology.

SDA technology is typically used on lower sulfur fuels (<2%). Further advantages of dry compared to wet FGD include: 1) less costly construction, 2) fewer process operations, 3) simplicity of control and operation, 4) lower water consumption, 5) lower auxiliary power consumption, 6) ability to use alkalinity in the flyash for  $SO_2$  absorption, 7) efficient reduction of  $SO_3$  emissions, and 8) production of dry solid byproducts without the need for dewatering. See Figure 7 for a picture of a typical dry FGD SDA.

CDS technology is another type of dry FGD system. It is primarily applied on units that are firing medium to high sulfur coals. This technology uses a fluidized bed for contacting the reagent with the  $SO_2$  in the flue gas. The reagent is typically hydrated lime. The intensive gas-solid mixing that occurs in the reactor promotes the reaction of  $SO_x$  in the flue gas with the dry lime particles. The mixture of reaction products (calcium sulfite/sulfate), unreacted lime, and flyash is carried to a downstream particulate collector that is separated from the gas stream. Part of the dry waste product is removed for disposal, but most of the waste product is mixed with fresh calcium hydroxide for use in

the reactor. Water spray is introduced into the fluidized bed separately from the dry reagent to enhance performance (for maximum  $SO_2$  capture with minimum lime utilization) by optimizing the surface moisture content of the lime. Circulating dry scrubbers can provide removal efficiencies up to approximately 98% depending on specific conditions of the application. Compared to wet FGD systems, capital costs are lower for CDS systems, and similar to an SDA, and there is the potential for higher  $SO_3$  reduction and lower PM emissions with use of an integral pulse jet fabric filter. The CDS also creates a dry solid byproduct and does not require a wastewater treatment facility. See Figure 8 for a diagram of a typical CDS.

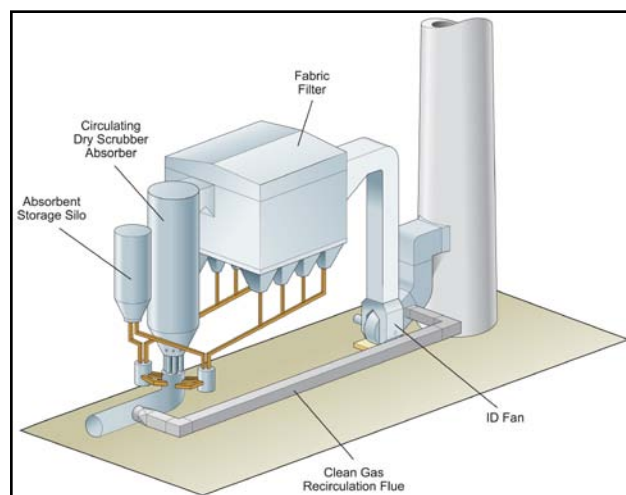
DSI is the lowest cost solution. These systems involve the injection of a dry sorbent (typically trona, sodium bicarbonate or lime) into the ductwork following the boiler.  $SO_x$  reacts directly with the dry sorbent, and the dry product is collected in a downstream particulate control device. Because a separate absorber vessel is not needed, capital costs are minimized. Low capital costs are partially offset by lower reagent utilization, which results in higher operating costs for equivalent  $SO_2$  removal rates. Dry injection systems are generally applied when lower removal efficiencies are required, or on small plants where the capital cost for other scrubber types may not be justified. Dry injection systems can typically achieve removal efficiencies ranging from 50 to 70% depending on the specific conditions of the application.



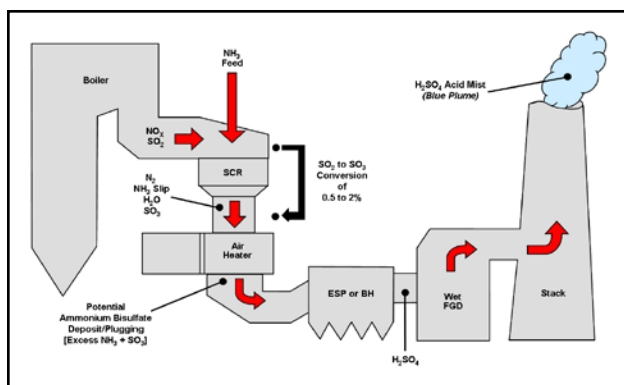
**Fig. 7** Typical dry FGD spray dryer absorber.

## $SO_3/H_2SO_4$ Control

$SO_3$  in the flue gas hydrates to form  $H_2SO_4$  vapor. As the flue gas temperature cools, the  $H_2SO_4$  vapor condenses to form a sub-micron aerosol (acid mist). Due to the small size of these aerosol particles (less than 0.5 microns), the acid mist is difficult to capture or collect as they pass through the final boiler heat traps (air heaters) and in the air pollution control equipment (ESPs, fabric filters and FGD systems). The acid mist that reaches the stack contributes to total particulate emissions and creates a challenge for meeting the most stringent particulate emission regulations.



**Fig. 8** Circulating dry scrubber with fabric filter.



**Fig. 9** Formation of secondary plume.

Over the past decade, efforts to remove  $\text{NO}_x$  through the use of SCR technology have resulted in increased  $\text{SO}_3$  concentrations in the flue gas stream of utility boilers that fire high sulfur fuels. This same problem has been encountered when firing fuels with high vanadium content which increase the  $\text{SO}_2$ -to- $\text{SO}_3$  conversion in the boiler. When flue gases containing as low as 5 to 10 ppmdv of  $\text{SO}_3$  are treated in a wet FGD system, the potential exists for a visible secondary plume to occur. The primary plume is composed of water droplets which dissipate readily. The secondary plume is less visible and typically only becomes apparent after the primary plume has dissipated. The secondary plume is caused by aerosols, primarily sulfuric acid, but ammonium bisulfate and other compounds also contribute. The color of the secondary plume is typically blue, but brown and other colors have been noted depending upon meteorological conditions, angle of the sun, other compounds, etc. See Figure 9.

There are two primary solutions to mitigate  $\text{SO}_3$ . A chemical solution, where a sorbent is injected into the flue work, or a hardware solution, such as a wet ESP located after a wet FGD.

## Sorbent injection

There are several sorbents that can be utilized to reduce the  $\text{SO}_3$  generated from a combustion source. These sorbent control methods include injecting chemicals in either the fuel or in the flue gas. These sorbents react in the flue gas to form a solid compound that can be removed in the particulate collection device such as an ESP or fabric filter.

Sorbent injection technologies for the mitigation of  $\text{SO}_3$  typically utilize alkaline-based reagents that contain calcium, magnesium, sodium or ammonia. Depending on the reagent used, these reagents can be injected dry or wet, and either in aqueous or slurry form. Dry injection typically uses pneumatic conveying equipment to transport dry solids from a storage silo to the flue gas. Injection of solutions and slurries has some disadvantages when compared to dry injection. Such wet injection generally requires longer residence times since the reaction typically occurs after evaporation. Also, poor atomization can result in agglomeration of ash on internal supports or other boiler island equipment depending on injection location.

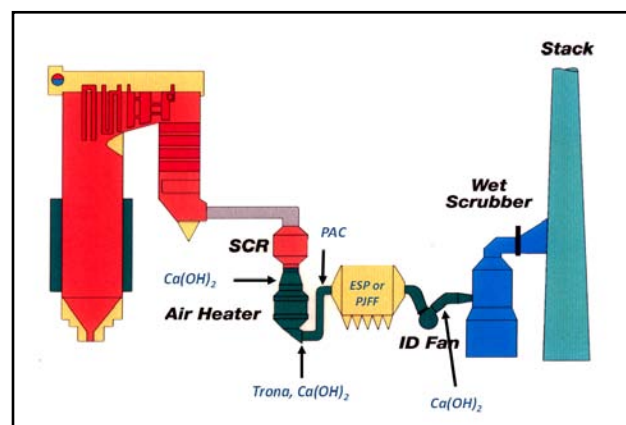
Several chemicals have been found to be successful at reducing  $\text{SO}_3$  concentrations when added downstream of the boiler furnace (upstream or downstream of the air heater), SCR, ESP or scrubber. These chemicals include magnesium oxide, calcium hydroxide, sodium bisulfate, ammonia, and sodium sesquicarbonate (trona). Each of these chemicals is effective in reducing  $\text{SO}_3$  emissions, but extreme care must be exercised in selecting the proper additive for a specific site. Consideration should be given to: temperature distribution across flues, characteristics of the additives and resulting salt formation, available residence time, amount and availability of additive, physical limitations of ductwork, internal structural supports, particle size of additive, flow distribution in ductwork, and potential impacts on flyash sales as well as reagent cost. Sorbents that are injected downstream of the SCR have an advantage because the sorbent removes the  $\text{SO}_3$  generated from both the boiler and SCR. Sorbents injected in the furnace can reduce  $\text{SO}_3$  before the SCR, but there could still be a visible sulfuric acid plume because of the  $\text{SO}_3$  generated when  $\text{SO}_2$  is oxidized by the SCR catalyst. Figure 10 shows the various injection locations for  $\text{SO}_3$  control.

## Wet ESP

The wet ESP is also an effective device to remove  $\text{SO}_3$ , especially when ultra-low outlet concentrations are required. Wet ESP systems have been serving the needs of industrial applications for nearly 100 years to control sulfuric acid and particulate emissions. Thousands of individual wet ESP modules are in worldwide commercial operation today.

Wet ESP technology can be used in coal-fired plants after the wet FGD as a final “polishing” stage to remove very fine particulate, sulfuric acid and any other mist. Fine particulates are removed more effectively in a wet ESP because of the humidity in the flue gas stream. Humidity reduces the resistivity of the particle.

For a given, site-specific constraints will need to be evaluated to determine the optimal wet ESP type and configuration (vertical downflow, vertical integrated, or horizontal stand-alone). Despite the higher initial capital costs, wet ESPs can be economical to own and operate. The additional



**Fig. 10** Various injection locations for  $\text{SO}_3$  control.



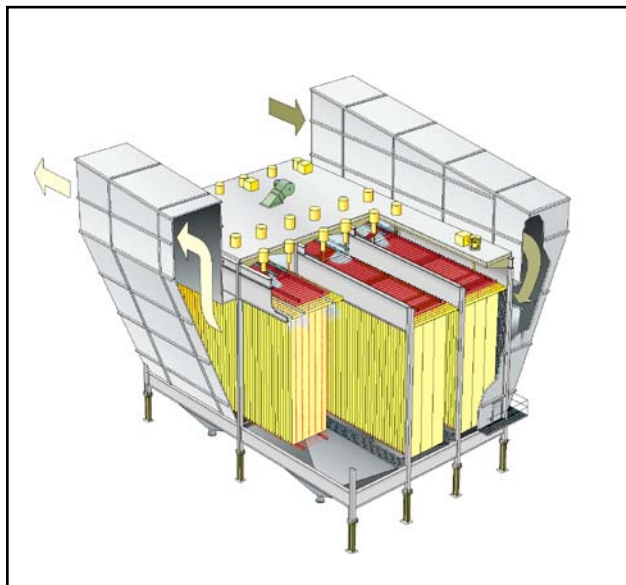
benefits in keeping solid particulates at very low levels, and the possible benefits in mercury control and hazardous air pollutants (HAPs), may make wet ESPs a desirable choice when considering the available options for SO<sub>3</sub> control. They are suitable for high sulfur fuel applications. It is typically used when sorbents will not achieve the desired results or when very fine particulate emissions are required. See Figure 11 for an example of a horizontal wet ESP configuration.

## Mercury Control

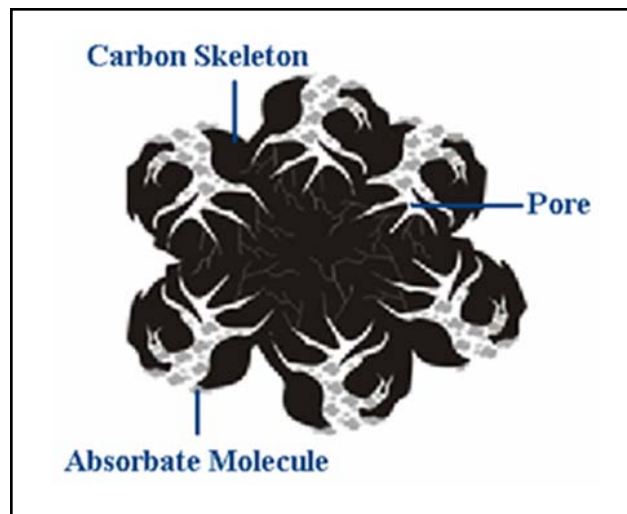
Mercury in some chemical forms is very toxic. If it finds its way into water sources, it can be converted into water soluble species, such as methyl-mercury, by microorganisms and accumulate in the fatty tissue of fish. Consumption of contaminated fish is the main risk to humans.

Powdered activated carbon (PAC) injected into the flue gas is the most established technology for mercury control, and can provide up to approximately 95% mercury capture for coals with high chlorine content. By adsorbing onto the surface of the PAC, the elemental, oxidized mercury and particulate mercury are removed in particulate control devices (ESP or fabric filter). Chemical modification of the PAC, such as halogenation, can improve the ability to capture mercury, but can also increase material costs.

PAC is carbon that has been treated with high temperature steam using a proprietary process to create large surface area. Figure 12 presents a diagram of a PAC particle. Each PAC particle consists of a carbon skeleton with numerous branching pores that provide a very high surface area-to-volume ratio. Pollutants, such as mercury, become adsorbed in the nanopores of the PAC particles, and are effectively removed from the flue gas stream. The sorbent activity varies with respect to each chemical species, with oxidized mercury having a greater rate of adsorption by PAC than elemental mercury. Standard PAC is only effective for mercury con-



**Fig. 11** Horizontal wet ESP.



**Fig. 12** Powdered activated carbon particle.<sup>[3]</sup>

trol at flue gas temperatures below about 165C (329F) for bituminous coal having higher chlorine content. Therefore, total mercury removal of over 90% may be attained for such bituminous coal using standard PAC when an SCR is part of the air pollution control system, but only about 60% removal could be expected for a coal with low chlorine using standard PAC injection. However, over 90% total mercury removal when burning low chlorine sub-bituminous coal has been achieved using halogenated PAC.

A typical PAC injection system consists of several components. A storage silo, as shown in Figure 13, is used for on-site PAC storage. Screw feeders then transport the carbon into a drop tube, from which it is fed to the eductor inlet below the feeder discharge where it is pneumatically conveyed to the flue work. The carbon-in-air mixture is metered into the flue gas flue with an array of injection lances.

As previously discussed, by halogenating the PAC, mercury capture may be increased. Therefore, lower sorbent injection rates are required to achieve the same mercury capture. Halogenated PAC is provided by suppliers who use proprietary methods to impregnate the carbon with the halogen species. In addition, the halogenation process alters



**Fig. 13** PAC injection silo.

the PAC properties such that halogenated sorbents may be effective at flue gas temperatures up to approximately 200C (392F), while standard PAC decreases in usefulness as flue gas temperatures exceed 175C (347F) when burning a low chlorine coal. Brominated PAC is the most commonly used carbon for mercury control because bromine is far more reactive than chlorine. Unlike standard PAC, injection of brominated PAC alone may provide adequate mercury removal rates for many plants. As an example, for applications with either an ESP or a pulse-jet fabric filter (PJFF), total mercury removals would be anticipated to improve from baseline rates of 10 to 50% to removal rates of 50 to 90% with brominated PAC injection.

Another unique challenge is PAC poisoning by SO<sub>3</sub>. When burning medium to high sulfur coal, SO<sub>2</sub> to SO<sub>3</sub> conversion (up to 2%) occurs in the boiler and across the SCR system. PAC consumption increases as SO<sub>3</sub> concentration increases above 5 ppm. At greater than 15 ppm, the PAC is much less effective in removing mercury. To mitigate this SO<sub>3</sub> impact, sorbent injection systems utilizing lime or trona can be installed to remove SO<sub>3</sub> before the point of PAC injection.

Mercury from low chlorine coal-fired units tends to have a higher proportion in elemental form, which is the most difficult form of mercury to remove from the flue gas stream. As discussed previously, a SCR will help by converting elemental mercury into oxidized mercury which improves its ability to be removed by PAC and other traditional environmental protection systems. The larger the amount of SCR catalyst that is installed, the greater the conversion of elemental mercury into oxidized mercury and the better the potential for removal of the mercury.

Additional methods that can be used to improve mercury removal in the environmental protection system of the plant includes use of a pre-combustion halogen-based fuel additive to help form more oxidized mercury (B&W PGG's MercPlus™ system, for example), and a wet scrubber slurry additive (B&W PGG's Absorption Plus (Hg)™ system, for example) designed to inhibit the reduction of captured oxidized mercury into elemental mercury and subsequent re-emission. Wet FGDs are effective for removing oxidized mercury. These additives enable effective removal

of oxidized mercury in the wet FGD, and may be used in combination or separately, as each is implemented at a different point in the process.

## Advanced Plant Configurations

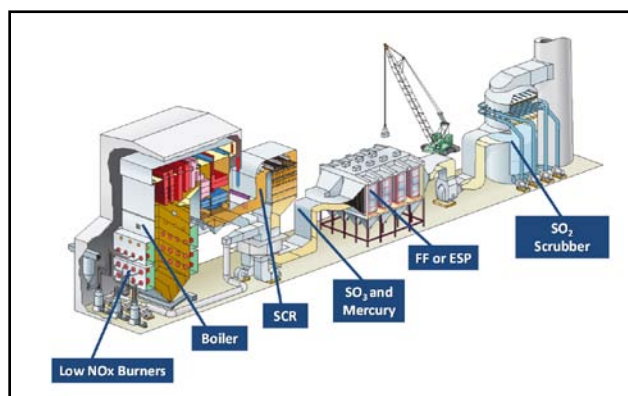
Various configurations of environmental control equipment for new coal plants will now be examined. A plant configuration for high sulfur bituminous coal includes low NO<sub>x</sub> burners, an advanced high removal efficiency SCR NO<sub>x</sub> removal system, dry sorbent injection, PAC injection, fabric filter or ESP (depending on requirements), and limestone wet FGD. A typical plant configuration is shown in Figure 14.

The plant configuration for low sulfur coal consists of low NO<sub>x</sub> burners, an advanced high removal efficiency SCR system, PAC injection, spray dryer absorber FGD system, and pulse jet fabric filter. This plant configuration is shown in Figure 15.

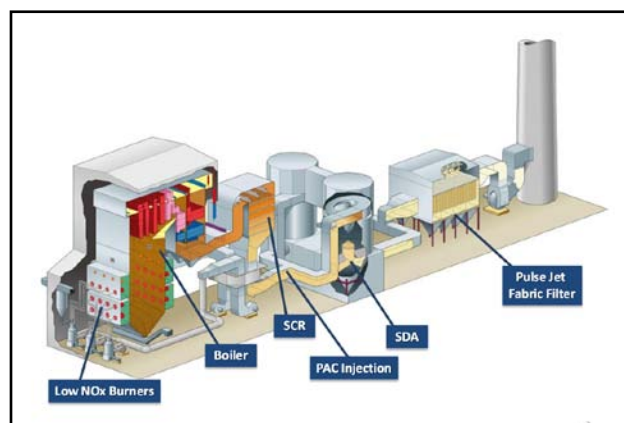
Table 2 shows the theoretical maximum removal efficiencies that can be achieved for various constituents and proper equipment configurations.

## Conclusions

Current and pending environmental regulations are becoming increasingly more stringent and intricate, encompassing more air emissions than ever before. Environmental equipment and systems utilized in a flue gas cleaning arrangement have typically been associated with the treatment of one particular pollutant. For example, an SCR system is used to reduce NO<sub>x</sub>. However, as emissions regulations become more stringent and utilities consider the use of a wide range of fuel types as is currently happening in Asia, the interrelated effects of each component or system in the arrangement on other pollutants must be recognized. Some of these effects are positive and some may be negative. For example, it is known that an SCR oxidizes elemental mercury into ionic (elemental) mercury. Oxidized mercury is much easier to remove in an FGD system. Thus, making the SCR larger will increase mercury removal in the FGD downstream. However, an SCR also oxidizes SO<sub>2</sub> to SO<sub>3</sub>,



**Fig. 14** Typical plant configuration for high sulfur bituminous coal.



**Fig. 15** Typical plant configuration for low sulfur coal.

**Table 2**  
**Typical Maximum Removal Efficiencies**

Expected Control Performance	FF/WFGD/WESP	ESP or FF/WFGD	CDS/FF	SDA/FF	DSI/FF
SO <sub>2</sub> (%)	98+	98+	98+	95 to 98	50 to 80
HCl (%)	99+	99+	98+	98+	80 to 95+
HF (%)	99+	99+	98+	98+	80 to 95+
Mercury* (%)	90	90	90 to 95	90 to 95	80 to 90
Non-Mercury Metallic HAP (%)	97 to 99+	97 to 99+	99+	99+	99+
PM Filterable (mg/Nm <sup>3</sup> @ 6% O <sub>2</sub> )	<3.7	<12.5	<12.5	<10.0	<10.0
Total PM (mg/Nm <sup>3</sup> @ 6% O <sub>2</sub> )	<16.1	<24.9	<24.9	<22.4	<31.0

\* Mercury control strategies may incorporate ACI, MercPlus™ or Absorption Plus (Hg)™ with the FGD technology as determined by site specific fuel and boiler conditions.

which can become sulfuric acid, H<sub>2</sub>SO<sub>4</sub>. Sulfuric acid forms a very fine mist, which is very difficult for a wet FGD to remove. Filterable (solid) particulate is removed in the wet scrubber. The wet scrubber tends to remove 40 to 90% of the flyash entering the scrubber, depending upon the ash inlet loading and the type and configuration of wet scrubber. However, further particulate control is needed to collect this material and to limit its release to the atmosphere. When a plant considers the use of air pollution control technologies, several areas of the boiler island and environmental protection system need to be evaluated to optimize the overall reduction of plant emissions.

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