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WORLDWIDE POLLUTION CONTROL ASSOCIATION

Working outside the box

Selective Catalytic Reduction (SCR) System Being Used in Unique Application

By Randy Sadler, ARGILLON Americas

Figure 1: Front entrance to Mitsubishi Cement Corporation terminal at Port of Long Beach, California

In a new and unique application of a SCR system, Argillon has designed and manufactured a SINOx® SCR system that will be used to primarily reduce oxides of nitrogen (NOx) for large ocean going vessels while at berth.

The SINOx® SCR system will abate emissions of Nitrogen Oxides (NOx) from Mitsubishi Cement cargo ships loading and unloading bulk material at the Port of Long Beach, (POLB) California. (See figure 1.) The SINOx® System will remove harmful emissions from the auxiliary diesel engines that are providing electric power while at berth. (See figure 13 on page 15.) These cargo ships also generate harmful emissions while entering and exiting the port. The SINOx® SCR system provided by Argillon will reduce NOx exhaust emissions by as much as ninety-eight (98) percent while these ships are at berth. In addition, the SINOx® SCR System will remove some particulate matter (PM), which has been well documented for its harmful effects on our health. (*continued on page 15*)

Covering all the bases

Fine Particulate Collection Using Dry Electrostatic Precipitators

By Robert A. Mastropietro, Lodge-Cottrell Inc.

INTRODUCTION

Potential legislation concerning fine particulate or $PM_{2.5}$ (particulate matter less than 2.5 microns), has been under discussion for several years. Atmospheric air quality is the issue that legislation is trying to address. However, stack emissions from stationary sources are only one contributor to atmospheric $PM_{2.5}$. Since $PM_{2.5}$ can come from a wide variety of sources (road dust, automobile exhausts, farm fields, acid condensation, etc.), $PM_{2.5}$ from stationary sources is only one source contributing to total atmospheric $PM_{2.5}$. Also, the $PM_{2.5}$ generated by stationary sources can come from two distinctly different sources; ❶ solid particulate emissions, and ❷ gaseous emissions which condense in the atmosphere. U.S. EPA studies (*continued on page 10*)

Inside

When two steps are better than one

A Cost Effective FGD Wastewater Treatment System

by Philip Elliott and Hans Hartenstein, STEAG LLC

Utilities are facing increased pressure from regulators, shareholders and customers to reduce mercury from their coal-fired boilers, but in the most cost effective manner as possible. A well known co-benefit of wet scrubbers is that they can remove mercury from the flue gas stream and prevent its introduction into the environment. However, the mercury from the flue gas usually ends up in the FGD wastewater treatment process and must be disposed of to avoid returning the mercury to the environment.

Conventional FGD wastewater treatment in a one-stage process results in the need for external disposal of the residue produced and consequently high disposal costs. Development of a two-stage process using selective mercury and heavy metal removal, while maximizing internal filter cake recycling, has allowed for greatly minimizing the amount to be disposed and up to a 97% reduction in filter cake disposal costs.

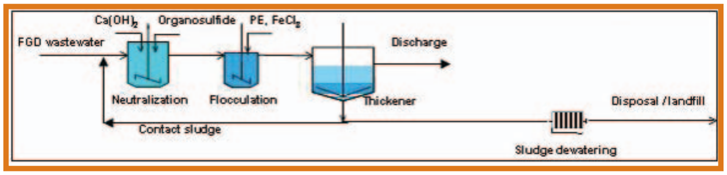

Figure 2: Conventional one-stage process

Coal releases mercury during the combustion process. Wet scrubbers remove the mercury by dissolving it in limestone slurry in the absorber tower and removing it through the blowdown process.

Due to the chemical properties of mercury, oxidized mercury is water soluble while elemental mercury is not. This property makes it essential to convert elemental mercury to oxidized mercury prior to entering the wet scrubber. When the oxidized mercury is exposed to the limestone slurry, it dissolves and remains in the slurry, effectively removing it from the flue gas. If mercury is left in the elemental state, it does not dissolve in the slurry and discharges through the stack.

There are three known processes that convert elemental mercury released during the combustion process to oxidized mercury. The first is the natural process that occurs in the boiler itself. Through the combustion process, elemental mercury reacts with oxygen and forms mercury oxide (HgO). The second process is the reaction of mercury with one of the halogen elements, specifically chlorine or bromine. These elements work to form a molecular bond with mercury that is very water soluble. The final method is by use of an SCR. The elemental mercury reacts with compounds in the SCR catalyst layers and oxidizes, thus is water soluble.

Limestone slurry in the absorber tower removes oxidized mercury that is in the flue gas by dissolving the oxidized mercury. The mercury remains in the limestone slurry and is blown down through the gypsum dewatering process. During this process, the heavy particles (gypsum) separate from the finer particles, of which oxidized mercury is a constituent. These finer particles are eventually part of the scrubber blowdown to the wastewater treatment process which removes these finer particles prior to the waste stream's discharge to the particular plant's effluent.

Typical conventional wastewater systems use a one-stage process that precipitates solids from the wastewater, including heavy metals such as mercury, and presses them out of the blowdown to make filter cake which is disposed. The majority of the filter cake produced is gypsum and other fly-ash inerts. However, because of heavy metals, especially mercury, the operating plant must dispose of the filter cake produced, usually at a considerable cost. Figure 2 is an example of a typical one-stage process.

The disposal costs can vary and range from \$50/ton to over \$100/ton. Considering a medium sized plant (400 MW) burning low sulfur coal averages 10 – 15 tons of filter cake per day (25 – 30 tons per day on high sulfur), there can be a substantial cost to the utility just to dispose of this waste stream.

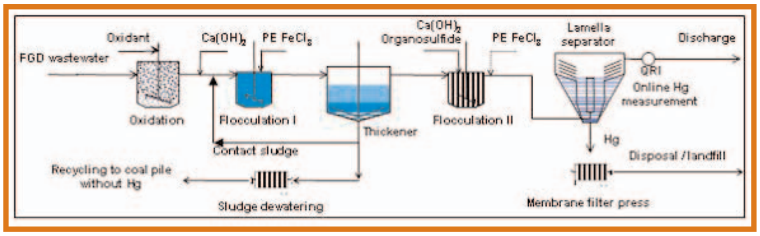

Figure 3: STEAG's patented two-stage process

For fifteen years, STEAG operated this type of wastewater system to treat blowdown from the wet scrubbers at considerable cost. Faced with pressure to reduce costs but still wanting to ensure the removed mercury was not reintroduced into the environment, STEAG developed and patented a two-stage wastewater treatment system in 2000. Figure 3 is an example of STEAG's two-stage process.

The first stage precipitates gypsum and other inerts out of the blowdown while keeping the mercury and other heavy metals in solution. A filter press removes the "metal free" product from the process. The filter cake produced during the first stage represents 97% of the filter cake produced in the conventional process. Because the filter cake is mercury free, the filter cake is recycled to the coal pile, consumed in the boiler and eventually removed through the plant's ash handling system. Testing at STEAG's facilities for mercury found no measurable change in mercury readings anywhere in the flue gas flow path.

The remaining solution, which contains the mercury and other heavy metals from the blowdown, will go through a second stage which will precipitate and separate the solids from the water. This filter cake, which is rich in mercury and other heavy metals, is then disposed of. This filter cake accounts for 3% of the conventional wastewater treatment filter cake.

In the conventional one-stage process, STEAG was spending approximately $797,506 per year to dispose of the filter cake. This cost was associated with the disposal of 6,500 metric tons of filter cake per year. Herne Plant (Unit 4) implemented the first two-stage process wastewater treatment system. After the start of the two-stage process, 97% of the filter cake produced was recycled to the coal pile, resulting in STEAG only disposing of approximately 200 metric tons of filter cake per year.

There was extra disposal cost per ton due to higher levels of mercury and the additional chemicals needed for the two-stage process. This represented a cost of $109,073 per year. However, by spending the $109,073 per year, STEAG avoids the $797,506 total disposal cost. By implementing this process, STEAG was able to save $688,526 and implemented this system at the other operating units at Herne as well as 5 other STEAG generating plants representing 13 treated units.

The largest operating cost of a wastewater treatment system is the disposal cost for the filter cake from the blowdown. It is normal for a plant to dispose of over 6,000 tons per year and STEAG plants were no different. However, because of the substantial costs associated with the disposal, STEAG developed a new two-stage process that would allow the "metal free" filter cake (97% of the original) be recycled to the coal pile and eventually consumed in the boiler. The remaining 3% was disposed of in a landfill resulting in a sizeable cost savings to the company and no reintroduction of mercury into the flue gas and environment.

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Expert tips

Hidden FGD Safety Issues

by Ron Richard, RE Consulting

A hidden safety issue in the form of "sulfate reducing bacteria" (SRB) lurks in most FGD systems. SRB are present in most ground and surface waters, so it is almost impossible not to find them in an FGD system. The hazard arises due to their normal life cycle and the sulfur compounds present in an FGD system.

The SRB live by stripping oxygen molecules from sulfate and sulfite compounds. While the bacteria can survive in the presence of air, they prefer to live and grow more quickly in areas that are free from air. Thus, they are often found in stagnant deposits of gypsum and calcium sulfite typically found in the bottom of sumps and tanks.

The problem is that this bacterial action produces hydrogen sulfide which is a toxic and flammable gas. While this doesn't cause a problem during system operation, it produces a safety hazard during normal maintenance activities. As crews clean the stagnant areas of sumps and tanks, they may experience a slimy black deposit that releases a "rotten egg" odor as they break it apart. This is the hydrogen sulfide gas being released from the deposit. If the odor disappears, it doesn't necessarily mean that the gas is gone, since at the higher lethal concentrations, hydrogen sulfide can cause paralysis of one's sense of smell.

Hydrogen sulfide is heavier than air and will collect in low areas. At a concentration above 10 ppm, it can cause eye damage, and above 300 ppm, it can cause pulmonary edema and possibly death. The lethal concentration where 50% of humans will die after five minutes is 800 ppm, and at 1000 ppm, it is possible for one breath of the gas to kill a person.

Proper ventilation to keep the hydrogen sulfide concentrations from accumulating is needed in work locations. Monitoring equipment should be used to indicate when hazardous levels of the gas are present. It is not difficult to mitigate the risk as long as people are aware of where these bacterial deposits will be located and what the indications are that hydrogen sulfide may be present.

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An old technology for new plants

SO_3 Control and Wet ESP Technology

by Patrick Doonan, James "Buzz" Reynolds, and Wayne Buckley
Wheelabrator Air Pollution Control, A Siemens Company

INTRODUCTION

In fossil fueled power plants, sulfuric acid mist is formed, when under certain conditions, sulfur trioxide (SO_3) reacts with water vapor (H_2O) to form sulfuric acid (H_2SO_4). The sulfuric acid mist is comprised of sub-micron aerosol droplets which form a dense white fume (sub-micron is typically in the range of 0.05 to 0.9 micron where a 1 micron droplet is one-thousandth of a millimeter in diameter). Wet electrostatic precipitation is a well-established control technology for sub-micron particulate as well as sulfuric acid mist.

New coal-fired power plants are now specifying WESP technology for control of SO_3 because the U.S. EPA has proposed more stringent New Source Performance Standards (NSPS) and National Ambient Air Quality Standards (NAAQS) including $PM_{2.5}$ regulations. New EPA $PM_{2.5}$ for existing sources and New Source Performance Standards for new coal fired plants will require control of both filterable and condensable particulate. Additionally, the Regional Haze Rule will likely require control of fine particulate and condensables in order to improve visibility in areas with National Parks. Finally, in some instances where Selective Catalytic Reduction technology has been installed for NOx control, oxidation of SO_2 to SO_3 has increased the visible plume through the further formation to sulfuric acid mist at the stack, and has created neighborhood and plant operational issues.

SO_3 AND H_2SO_4 FORMATION

Sulfur Dioxide (SO_2), Sulfur Trioxide (SO_3) and Oxides of Nitrogen, mainly NO and NO_2, are generated during the combustion of certain fossil fuels. Electric power generating units contribute more than 70% of the national SOx emissions.

When significant volumes of flue gas containing these oxides are discharged to the atmosphere, various state or local authorities set standards for the regulation of these pollutants, since they may impair human health.

Sulfur Trioxide (SO_3), which is hydrated to form sulfuric acid (H_2SO_4) from moisture contained in the gas stream or in the atmosphere, may also violate local opacity regulations. Visibility reduction related to air pollution is caused primarily by 0.1 to 1.0 micron diameter particles at a concentration of 1ppm (v) or greater at the stack outlet. Because of their small size and light refraction properties, these particles are also the main causes for the dense white plume formation at the stack.

While SO_2 emissions can be reduced using commercial flue gas desulfurization (FGD) technology and NOx emissions can be abated by selective catalytic reduction (SCR) or other processes, the removal of SO_3 and the control of aerosol sulfuric acid (H_2SO_4) is not as straight forward. Depending upon the type of FGD technology utilized, a considerable portion of these aerosols may exit the stack (30 – 60%) as a respirable sub-micron fine particle emission, which presents an extremely difficult air pollution control problem.

Sulfuric acid formation takes place through the reaction steps of:

—Oxidation of SO_2 to produce SO_3 (1) followed by reaction with H_2O to form H_2SO_4 (2):

—$SO_2 + {}^1/_2\, O_2 \rightarrow SO_3$ (1)

—$SO_3 + H_2O \rightarrow H_2SO_4$ (2)

Flue gas which has passed through a selective catalytic reduction (SCR) system, an air preheater and a dry electrostatic precipitator (DESP), normally ranges between 140-160°C. After scrubbing in a wet FGD process, the gas temperature usually drops to 55 - 60°C. To minimize condensation of acidic liquor, which causes stack corrosion and in some cases acid rain, the flue gas should be reheated to about 80°C, and to eliminate the formation of any visible plume, the flue gas temperature should be about 140°C. Obviously, for large gas flow rates, such as a utility boiler exhaust, gas reheating is very costly and, while reheating can minimize the visible plume caused by sulfuric acid and water vapor, it cannot remove solid particulate or reduce existing acid emissions to satisfy environmental mass emission limits.

If reduction of mass emissions, stack opacity or both are required, it is necessary to use a technology that will simultaneously remove both sulfuric acid mist and solid particulate material from the flue gas. Wet electrostatic precipitation (WESP) technology can satisfy this requirement and, as proven in numerous industrial applications, has the added potential for abatement of heavy metals (including mercury), as well as water mist carryover from an FGD scrubber system, while minimizing both the capital and operating costs.

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How low can you go?

SO_3 Measurement with EPA Method 8

by Scott Evans, CleanAir Engineering

When EPA began its stationary source emission monitoring program almost 30 years ago, the emission profile of a power plant was quite different than it is today. Stack concentrations of say, SO_2 and NOx in the thousands of ppm, were commonplace. It was under these conditions that many of the EPA Reference Methods, used to measure stack pollutants, were developed.

Today, the situation is quite different. We are now being asked to measure pollutants at low ppm or even sub-ppm concentrations. Yet, the tools are the same-- the same reference methods that have been around for the past 30 years. Not surprisingly, some of these methods are problematic when used for concentrations and matrices for which they were not intended.

EPA Method 8, "Determination of Sulfuric Acid and Sulfur Dioxide Emissions from Stationary Sources", is a case in point. This method was developed and validated for use in sulfuric acid plants -- sources with clean, bone-dry stack gas -- yet this method routinely shows up in permits and equipment contract guarantees for power plants. Those who are experienced in using the method have a sense of how much the precision and accuracy is degraded when used in a power plant flue gas matrix, but there has been very little research done to quantify this. With opacity and blue plume issues arising due to the oxidation of SO_2 across SCR catalyst beds, there is great interest in measuring very low SO_3 concentrations. We have been asked to verify SO_3 emissions with Method 8 to a permit limit or performance guarantee level of 0.01 ppm! The question "How low can you go?" comes up frequently.

Now granted, controlled condensation is the preferred method for measuring SO_3 in these applications. However, it is not an EPA Reference Method or even an ASTM method at this point, so convincing a regulatory authority to allow the use of this method can sometimes be difficult.

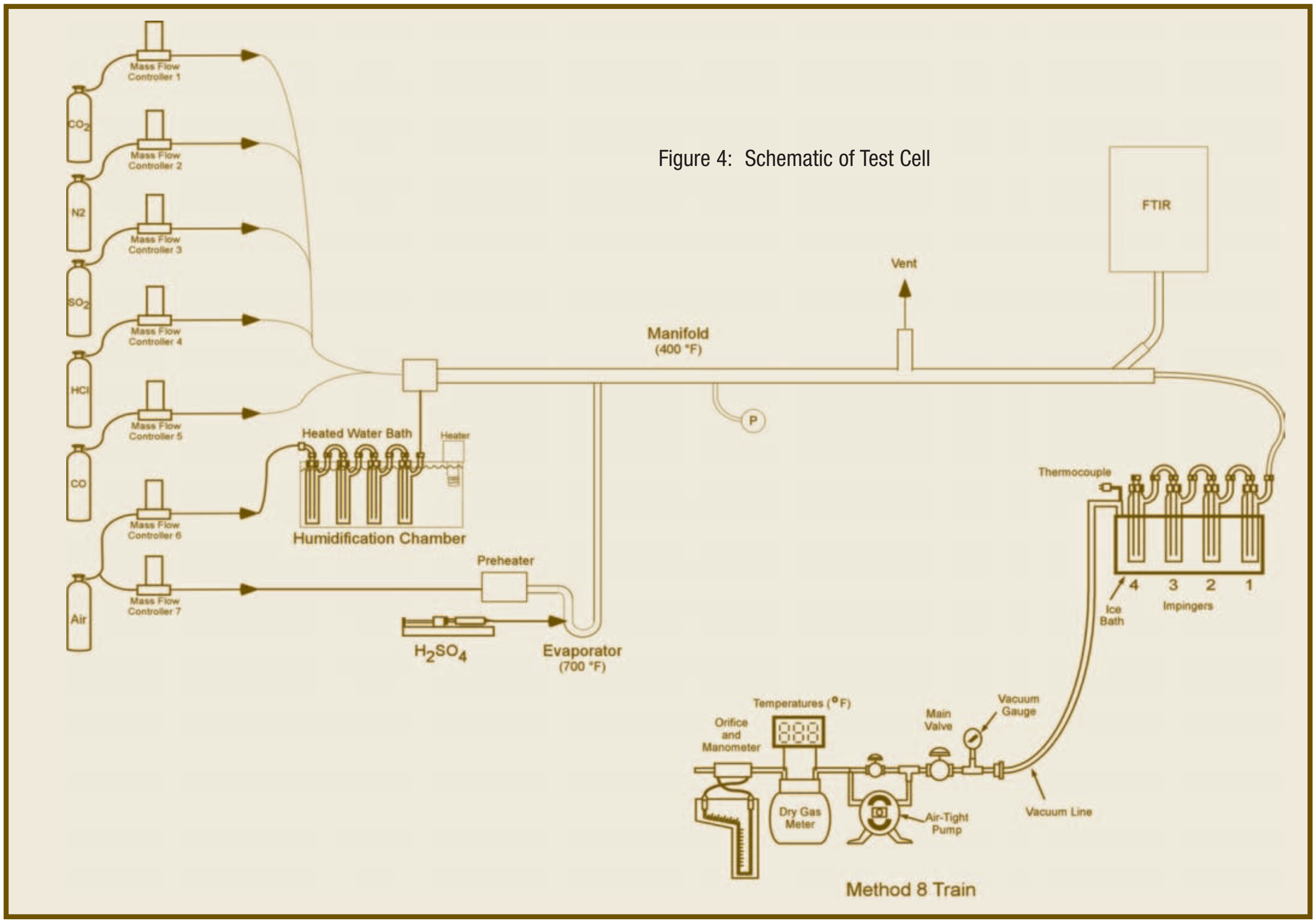
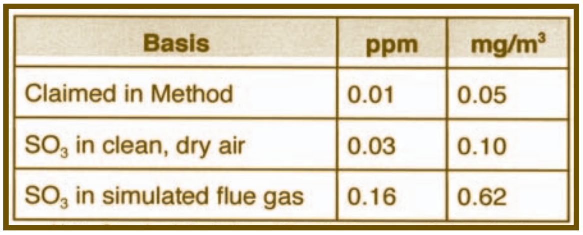


Figure 4: Schematic of Test Cell

To help answer the “How low can you go?” question, CleanAir Engineering undertook a study to determine a realistic in-stack detection limit for Method 8. While there is a detection limit stated in the method, it is generally felt that this is not realistic for power plant applications. The study also attempted to determine the accuracy of the method in a power plant flue gas matrix. While a full discussion of the results is beyond the scope of this article, a few highlights from the study will help to understand the problems associated with low concentration measurement.

To conduct this study, a test cell simulating power plant flue gas, as shown in figure 4 on page 5, was used. Fixed parameters included NOx, HCl, CO, and CO_2. Variables included H_2O, SO_2, SO_3, and O_2. The focus was on measurements in the 0.1 to 0.5 ppm range.

Results of the detection limit portion of the study are shown below in figure 5.



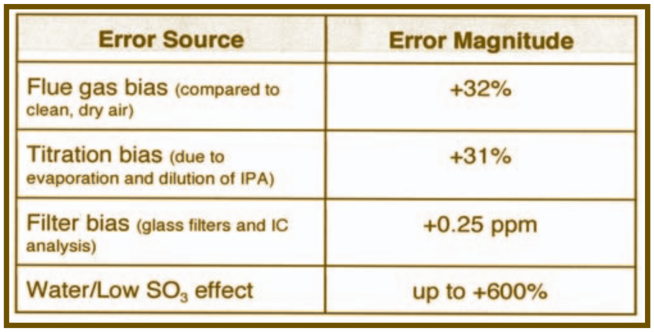
Basis	ppm	mg/m³
Claimed in Method	0.01	0.05
SO_3 in clean, dry air	0.03	0.10
SO_3 in simulated flue gas	0.16	0.62

Figure 5: In-stack detection limits for EPA Method 8

Note: Standard deviation of 7 replicate runs x 3.143 (99% Student’s t, n-1 df) following 40 CFR 136 Appendix B

Note that the in-stack detection limit determined by this study is an order of magnitude higher than that claimed in the method. Does this mean that Method 8 can produce reliable measurements down to 0.16 ppm? Not quite. Often forgotten (or ignored) is that measurements at or near the detection limit are qualitative, not quantitative. The signal to noise ratio at that level is high enough to determine that the analyte is present but not high enough to provide a quantitative value. The Practical Quantitation Limit (PQL) is the value recognized by EPA as the quantitative threshold. It is typically about three times the detection limit. Based on the results of this study, the PQL for Method 8 would be around 0.5 ppm. This is how low you can go.

A detection limit is a measure of precision or repeatability. It is a determination of the random error of the measurement. However, the wrong number can be measured very precisely. In order to determine measurement accuracy, the systematic error, or bias, must also be estimated. In our study, we generated known quantities of SO_3 (actually H_2SO_4 vapor), and determined the recovery under a variety of conditions. A summary of some of the results are shown in figure 6.



Error Source	Error Magnitude
Flue gas bias (compared to clean, dry air)	+32%
Titration bias (due to evaporation and dilution of IPA)	+31%
Filter bias (glass filters and IC analysis)	+0.25 ppm
Water/Low SO_3 effect	up to +600%

Figure 6: Systematic Error Sources (Bias) for EPA Method 8

Detailed descriptions of these bias determinations are beyond the scope of this article. They are presented here only to demonstrate the problems with the Method when applied to power plant emissions. Note that these biases are all positive -- they result in an over-reporting of SO_3 concentrations.

Other researchers have found additional systematic errors when Method 8 is used under certain conditions. England has described a positive bias in the presence of ammonia of up to 2.5 ppm. Daugherty has described the scrubbing effect produced when the sample gas is drawn through flyash on the filter. This is the only negative bias found.

So what is a power plant to do if an SO_3 measurement by Method 8 is required? First, make every attempt to substitute the controlled condensation method. This method is very similar to Method 8, except that it replaces the problematic IPA impinger with a condenser that is kept at a temperature above the water dew point but below the acid dew point. The detection limit is similar to Method 8, but many of the bias issues are reduced or eliminated. When specifying controlled condensation, it is important to be specific about which “flavor” of this method you wish to use. Since it is not an EPA reference method or an ASTM method anymore (it was withdrawn in 1978), there are several versions of the method floating around. The choice of which controlled condensation method you use could affect the results.

If, however, you are stuck using Method 8, there are a few things you can do to improve your detection limit and minimize bias effects.

- Always use the purge suggested in the method. Do this as soon as possible after the conclusion of the test run. If possible, use nitrogen rather than air.
- Before titration, bring the pH of the sample up to 4.5.
- Determine the IPA content of the sample prior to titration and add 100% IPA to bring the sample back to 80% IPA.
- Use only quartz filters, not glass.
- Use only experienced analysts. Very small analytical errors can add up to very large errors in the final result.

Some of these suggestions require approval by the regulatory authority. Even with the use of these suggestions, significant positive bias is likely to occur. These biases are directly proportional to the moisture content of the gas stream. In saturated gas streams, with water droplets present (i.e. after a wet scrubber), accurate SO_3 determination is simply not possible with Method 8 or possibly even with controlled condensation.

CleanAir is committed to leading the investigation into SO_3 and other acid gas measurement issues facing the power industry, but the magnitude of this effort will require additional industry participation and funding.

For more information, contact Scott Evans at sevans@cleanair.com

SO_3 Control and Wet ESP Technology

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WET ESP HISTORY

One hundred years ago, in 1907, Dr. Cottrell developed the first successful industrial Wet ESP for the E.I. du Pont de Nemours Powder Co. at Pinole, California, to recover sulfuric acid mist from a 200 cfm gas on a Mannheim contact sulfuric acid unit. Dr. Cottrell observed that "These gases at the point selected contained about 4% by volume of dry gaseous sulfur trioxide, and in order to convert this into sulfuric-acid mist, they were brought into contact with water. Under these conditions, very little of the sulfur trioxide is absorbed by the liquid water, but the water evaporating into the gas combines with the sulfur trioxide to form the far less volatile sulfuric-acid, which immediately separates as a dense white cloud of suspended particles so fine as to represent one of the most difficult of all materials to remove by filtration."

In 1908, Dr. Cottrell installed the next Wet ESP that handled a stack nuisance problem of 5,000 cfm of sulfuric acid mist from the recovery of silver from a lead processor at the Selby lead smelters in Selby, California, which caused a visible plume due to sulfuric acid emissions. The next Wet ESP followed in 1910 at the Balaklala copper smelter in Coram, California, on a 250,000 cfm copper smelter flue gas. The Wet ESP technology has since become a standard piece of process equipment for the sulfuric acid industry for over 50 years to abate H_2SO_4 mist in both process equipment and stack opacity.

In the past ninety years, Wet ESP technology has been employed in numerous industrial applications for plume reduction associated with $PM_{2.5}$ and H_2SO_4 mist, as well as for removal of toxic metals in the flue gas of hazardous waste incinerators.

While there are hundreds of installations worldwide in industrial facilities, and close to thirty installed in Japanese utilities, wet electrostatic precipitation is a relatively unknown technology to most U.S. utilities because air regulations up to recently have not required high levels of control of sub-micron particulate or condensables. However, as regulations emerge requiring stringent control of sub-micron particulate—which includes acid mists, metals, and some forms of mercury—wet ESP technology is increasingly attractive due to its low pressure drop, low maintenance requirements, high removal performance and reliability as a final polishing device.

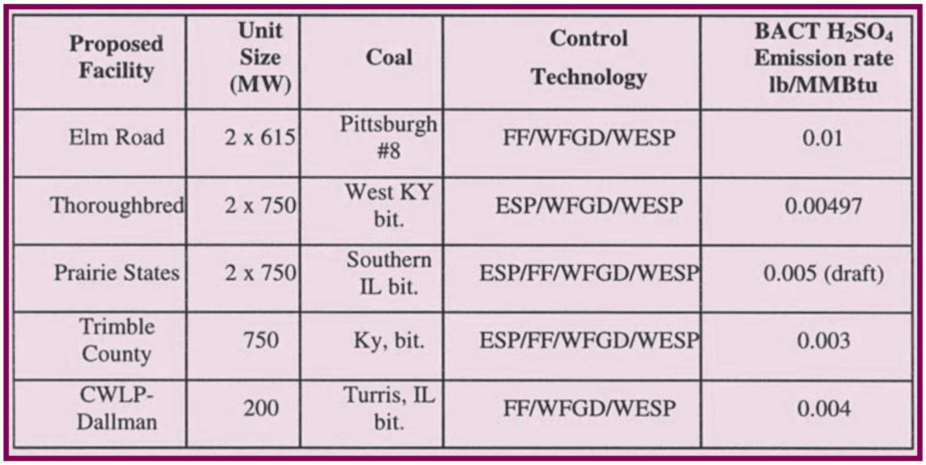
WET ESP TECHNOLOGY

While utilities have installed dry ESPs and fabric filters to collect course particulate and Wet FGD systems to scrub SO_2 acid gas from the flue gas, none of these APC devices can effectively control SO_3. SO_3 exists as a vapor at temperatures above 300°F (149°C) which is typically where a dry ESP or fabric filter is located, and the vapor will pass right through these particulate collection devices. Where no Wet FGD is installed, the flue gas will mix with ambient air upon exiting the stack, cool and condense the SO_3 into H_2SO_4. The sulfuric acid mist in the exiting flue gas is typically seen as a dense white fume sometimes with a trailing blue plume after the water vapor plume has disappeared.

If a Wet FGD system is installed, the SO_3 condenses to a droplet within the absorber vessel and then forms a sulfuric acid mist in the absorber vessel. However, because the majority of the sulfuric acid mist is sub-micron in size, the Wet FGD absorber cannot effectively collect these size particles and the mist exits the Wet FGD.

The effect of sub-micron particles is such that as the particles become smaller, gravitational and centrifugal forces become less powerful while electrical and, to a lesser degree, Brownian forces, become greater. Consequently, electrical collection is the most effective method for separating sub-micron particles and mists from a gas stream.

Most importantly, whereas mechanical collectors exert their force upon the entire gas, ESPs exert their force only upon the particles to be collected. ESPs typically operate at around 0.5-1.0 inches of water column pressure drop, regardless of air volume or particle size. Alternatively, a



Proposed Facility	Unit Size (MW)	Coal	Control Technology	BACT H_2SO_4 Emission rate lb/MMBtu
Elm Road	2 x 615	Pittsburgh #8	FF/WFGD/WESP	0.01
Thoroughbred	2 x 750	West KY bit.	ESP/WFGD/WESP	0.00497
Prairie States	2 x 750	Southern IL bit.	ESP/FF/WFGD/WESP	0.005 (draft)
Trimble County	750	Ky, bit.	ESP/FF/WFGD/WESP	0.003
CWLP-Dallman	200	Turris, IL bit.	FF/WFGD/WESP	0.004

Figure 7: Several new coal-fired power plants and the air pollution control equipment configurations proposed including the Wet ESP (WESP).

mechanical collector, such as a venturi scrubber, would have to operate at around 60 inches of water column to achieve 95 percent collection efficiency on 0.2 to 0.5 micron size particles.

The electrostatic precipitation process consists of three steps:

1) Charging the particles to be collected via a high-voltage electrical discharge.

2) Collecting the particles on the surface of an oppositely charged collection electrode surface.

3) Cleaning the surface of the collecting electrode.

Wet ESPs operate in the same three-step process as dry ESPs—charging, collecting and finally cleaning of the particles. However, cleaning of the collecting electrode is performed by washing the collection surface with liquid, rather than mechanically rapping the collection plates as in the dry. While the cleaning mechanism would not be thought to have any impact upon performance, it significantly affects the nature of the particles that can be captured, the performance efficiencies that can be achieved, the design parameters and operating maintenance of the equipment. Simply stated, wet ESP technology is significantly different than dry ESP technology.

Because true Wet ESPs continually wet the collection surface area and create a slurry that flows down the collecting wall to a recycle tank, the collecting walls never build up a layer of particulate. Consequently, there is no deterioration of the electrical field due to resistivity or buildup, and power levels within a Wet ESP can be dramatically higher than in a dry ESP. The ability to obtain much greater electrical power within the Wet ESP and the elimination of secondary re-entrainment are the main reasons a Wet ESPs can collect sub-micron particulate more efficiently than a dry ESP. Captured particulate flows continuously down the collection wall in suspension to an external tank for treatment thereby preventing re-entrainment or material buildup inside the casing.

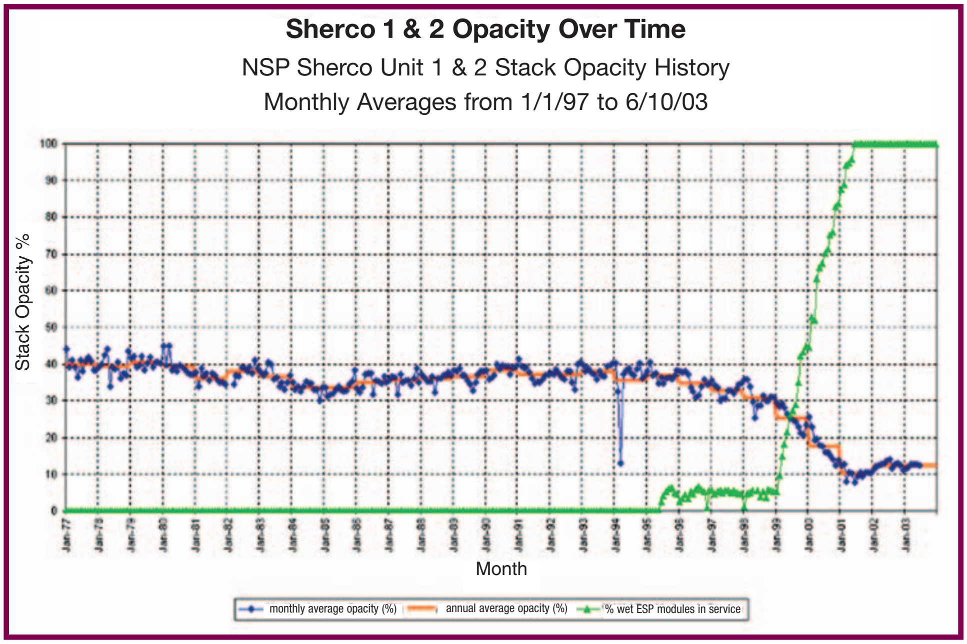


Figure 8: The Sherco Station "Opacity versus Time" graph is a good visual indicator of how rapid and effective the Wet ESP technology is on this utility applications opacity due to sub-micron particulate.

Because Wet ESPs operate in a wet environment, they can handle a wider variety of pollutants and gas conditions than dry ESPs. Wet ESPs find their greatest use in applications where gas streams fall into one or more of the following categories:

- The gas in question has a high moisture content
- The gas stream includes sticky particulate
- A high efficiency collection of sub-micron particulate is required
- The gas stream has acid droplets or H_2SO_4
- The temperature of the gas stream is below the dew point

Wet electrostatic precipitation technology can be used in utility air pollution control systems to control acid mists, sub-micron particulate (for example mercury and toxic metals), and as the final polishing device prior to the stack.

WET ESP UTILITY APPLICATIONS

While regulations to control PM10, NOx and SO_2 already exist, new coal-fired plants are being required to also reduce mercury, particulate matter less than 2.5 microns in size ($PM_{2.5}$) and condensable hazardous air pollutants, by both federal and state regulatory authorities.

New EPA $PM_{2.5}$ standards will require control of both filterable and condensable particulate to proposed 35µg/m³ levels and New Source Performance Standards are becoming more stringent with $PM_{2.5}$ standards of 0.015 lb/MMBtu.

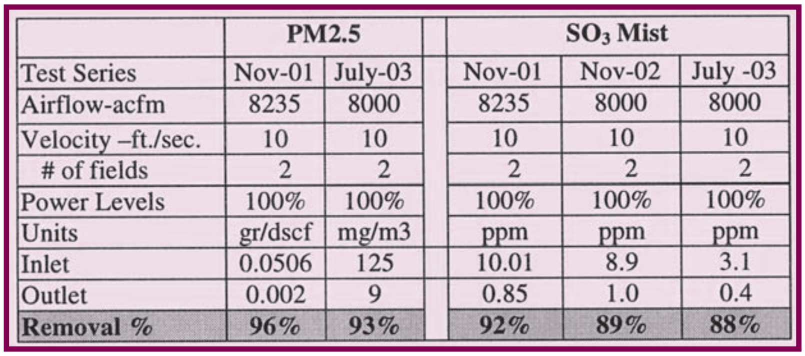
Wet ESP technology offers the ability to control both solid and condensable sub-micron particulate, including sulfuric acid mist, to meet new particulate standards and reduce the opacity of the visible plume. In fact, several new coal-fired power plants are requiring a Wet ESP in the air pollution control system as the final polishing device after the FGD system. Figure 7 shows several new coal-fired power plants and the air pollution control equipment configurations proposed including the Wet ESP (WESP).

The following are two cases of Wet ESP technology applied to a coal fired utility following a wet scrubber/absorber. The first case, Sherco, is a full scale Wet ESP installation and the second, Bruce Mansfield, is a comprehensive study of a unique Wet ESP technology applied to a 3% sulfur coal application.

Wet ESP at Sherco Station Coal fired plants are starting to recognize the need for Wet ESP technology to reduce $PM_{2.5}$ and SO_3 concentrations in the flue gas as well as to reduce visible opacity. One solution to these new emission challenges is installed since 2001 at Xcel Energies Northern State Power Sherburne County (Sherco) Station, Minnesota, which has two 750 MW boilers. Eleven modules of Wet ESPs were installed after each WFGD absorber vessel. Opacity was reduced from over 40% to less than 10% with all twenty-two Wet ESP modules in service as represented in figure 8. The blue and red lines represent opacity and start at 40%, while the green line represents the percentage of the 22 Wet ESP modules that are in service, and starts at zero. As the green line increases, modules are coming online, the blue and red lines (the opacity) decreases, until 100% of the modules are online then opacity drops to 10%.

The Sherco Station "Opacity versus Time" (figure 8 on page 8) is a good visual indicator of how rapid and effective the Wet ESP technology is on this utility applications opacity due to sub-micron particulate.

Pilot Wet ESP at Bruce Mansfield At FirstEnergy's Penn Power's Bruce Mansfield Plant (BMP), located in Shippingport, PA., a pilot WESP was installed using a slipstream of flue gas from the exhaust of the FGD system on boiler unit No. 2 which has a rated capacity of 835 MW and burns 3% sulfur coal. The plant installed the pilot WESP to test for $PM_{2.5}$ and SO_3 mist removal as a potential control technology to reduce visible emissions.



	PM2.5			SO₃ Mist		
Test Series	Nov-01	July-03		Nov-01	Nov-02	July -03
Airflow-acfm	8235	8000		8235	8000	8000
Velocity –ft./sec.	10	10		10	10	10
# of fields	2	2		2	2	2
Power Levels	100%	100%		100%	100%	100%
Units	gr/dscf	mg/m3		ppm	ppm	ppm
Inlet	0.0506	125		10.01	8.9	3.1
Outlet	0.002	9		0.85	1.0	0.4
Removal %	**96%**	**93%**		**92%**	**89%**	**88%**

Figure 9: The test results of the wet ESP from November 2001, November 2002 and July 2003.

An initial series of tests completed during Sept. of 2001 were performed in a single electrical field at approximately 8,000-cfm. In order to improve removal efficiency within the wet ESP pilot, the electrical system was subsequently retrofitted from a single to a two-field configuration within the same casing per a WAPC patent. All testing has been performed at 8,000 acfm, 60% beyond the design airflow of 5,000 acfm. Because a wet ESP is a volumetric device, it is very sensitive to air flow. Increase in velocity decreases performance due to less time to collect particulate among other reasons. Conversely, reducing air flow increases performance. If testing had been done at the designed air flow of 5,000 acfm, all test results would most likely have improved from those shown at the 8,000 acfm air flow.

Figure 9 shows the test results of the wet ESP from November 2001, November 2002 and July 2003. Only SO_3 testing was performed during 2002 due budgetary constraints. All testing was performed by two different independent outside third parties. The WESP was configured with two electrical fields in series. The November 2001 test showed removal efficiency of 96% for $PM_{2.5}$ and 92% for SO_3. The November 2002 SO_3 test was consistent with the previous year with 89% removal reported. The July 2003 testing showed 93% removal of $PM_{2.5}$ and 88% on SO_3. Differences in reported results are attributable to test method inaccuracies, test personnel experience and instrument calibration.

The important points of the test results are:

- The WESP achieved relatively high removal efficiencies on both solid particulate and SO_3
- The results by two different testing parties were consistent with one another
- Results from three different time periods were consistent with one another.
- Removal efficiency for $PM_{2.5}$ was always slightly higher than for SO_3 mist, likely due to particle size distribution.

CONCLUSION

Wet ESP technology is a proven, well-known technology that can achieve greater than 90% removal of sub-micron acid mist, solid particles and aerosols with low pressure drop and minimum maintenance. Opacity, a function of $PM_{2.5}$ and SO_3 concentration, can be reduced to less than 10%. As a final polishing device in an air pollution control system, a WESP offers excellent pollutant control capability that can meet new EPA regulations for solid particulate and condensables. Coal fired plants are starting to recognize the need for wet ESP technology to reduce $PM_{2.5}$ and SO_3 concentrations in the flue gas as well as to reduce visible opacity.

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Fine Particulate Collection Using Dry Electrostatic Precipitators

continued from front page

have shown that $PM_{2.5}$ in the Eastern U.S.A. atmosphere consists of nearly 50 % condensable sulfates, nitrates, and ammonium. Unfortunately, the ESP is a device which only collects solid particulate, and does not collect these condensable materials (note that a fabric filter is also just a dust collector). Therefore, gaseous species will pass through the ESP to the atmosphere with no control by the ESP. If control of gaseous species is required, a wet flue gas scrubber, or dry/semi-dry injection of sorbents ahead of the dust collector (ESP or FF), must be used.

DISCUSSION

When designing ESPs to collect $PM_{2.5}$ or even PM in general, the test method becomes extremely critical. The most common particulate test methods in use today in the U.S.A. are listed below, with comments on the amount of condensable material that is included as particulate;

Test Method	Comments
EPA 17	Measures particulate (rocks) only
EPA 5F	Measures particulate (rocks) only
EPA 5 (320F Probe Temperature)	Particulate plus small level of sulfuric acid
EPA 5 (248F Probe Temperature)	Particulate plus high levels of sulfuric acid
EPA 5 (180F Probe Temperature)	Particulate plus most sulfuric acid
PM 201	Particulate plus all sulfuric acid
PM 202	Particulate plus all sulfuric acid

Depending on the test method required for permitting, the solid particulate (rocks) can make up all or only a part of the measured “particulate”. Often-times, people refer to the front half catch as the “filterable” particulate. There is no more ambiguous term in the air pollution industry than “filterable” particulate. To the EPA, when discussing the atmospheric particulate, filterable particulate means solid particulate plus all condensable particulate. EPA test methods 201 and 202 clearly state their intent to include condensibles as particulate. To an ESP vendor, filterable particulate means solid particulate (rocks) only (as measured by EPA Test Methods 17 or 5F). After all, solid particulate is all that an ESP collects and is therefore all the ESP vendor can guarantee. Sometimes ESP systems have to be designed for extreme low solid particulate emissions, so that the sum of solid particulate plus condensibles (i.e. the so-called filterable particulate) meets the environmental compliance method/limit. Note that this same discussion applies equally to fabric filters, which also only collect solid particulate.

1. ESPs for Electric Utilities

With regard to the impact of ESPs on the solid particulate, studies have been performed on the particle sizes of particulate entering and leaving ESP's on pulverized-coal fired boilers (i.e. electric utilities). We have found first that the measurement of particle size is an imprecise science. Depending on the test method, different results are possible. For example, typical mass mean particle size distributions for pulverized-coal fired boilers (at the ESP inlet) with various test methods would be as follows;

Test Method	Typical Mass Mean
Insitu Plate Type Impactor (Anderson)	5 Microns
Centrifugal Laboratory Sizing (Bahco)	12 Microns
Insitu Cyclonic Impactor (Brinks)	16 Microns

Thus, even when discussing solid particulate only, there is confusion as to just what portion of the particulate is what particle size. However, for the purposes of this paper, we have based the following discussion on Bahco test data. We chose Bahco because there tends to be more historical data available on outlet particle size using a laboratory device.

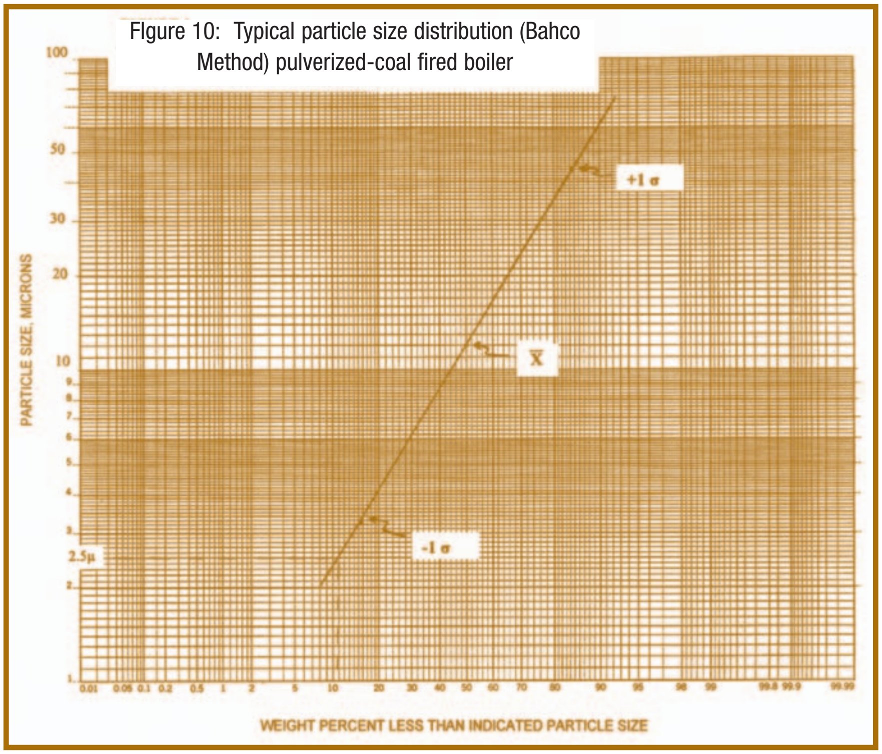


FIgure 10: Typical particle size distribution (Bahco Method) pulverized-coal fired boiler

A high efficiency ESP will emit particles both larger and smaller than 2.5 microns. And the particle size distribution will get finer and finer as the ESP efficiency increases. This is because the ESP is more efficient on large particles than small.

If we consider a typical coal analysis (i.e. HHV=12,000 Btu/lb and 12 % ash), the total solid particulate ESP inlet concentration would be;

1,000,000 BTU / 12,000 BTU/lb * 0.12 Ash * 0.85 Carryover = 8.5 lb/MMBtu

From historical data, a typical particle size for a utility pulverized-coal fired boiler would be a mass mean of 12 microns and a standard deviation of 3.8. The particle size distribution would be as shown on figure 10.

From figure 10, we can see that about 11 % of the incoming solid particulate will be $PM_{2.5}$. Thus the inlet loading of $PM_{2.5}$ would be;

8.5 lb/MMBtu * 0.11 = 0.935 lb/MMBtu of inlet $PM_{2.5}$

Particle size measurements have been made on the outlet particle size distribution from high efficiency ESP's. These studies have shown that as the collection efficiency of the ESP gets higher, the outlet particle size distribution gets smaller. Typically, the percentage $PM_{2.5}$ in the outlet particle size distribution for an ESP achieving U.S.A. New Source Performance Standards of 0.03 lb/MMBtu (approx. 30 mg/NM^3), was in the range of 50 % of the outlet particulate. Therefore in this case, we would calculate that the mass emissions of $PM_{2.5}$ micron particulate with a total emission of 0.03 lb/MMBtu would be;

0.03 lb/MMBtu * 0.50 =
0.015 lb/MMBtu of $PM_{2.5}$

Thus, the overall calculated efficiency of this ESP on $PM_{2.5}$ would be;

(0.935 - 0.015) / 0.935 = 98.4 % on $PM_{2.5}$

Note that the overall efficiency on total particulate would be;

(8.5 - 0.03) / 8.5 = 99.65 % on all particulate

So, as mentioned above, the ESP is less efficient on fine particles than large, but ESPs do collect fine particles at high efficiency.

Of course, the above calculations assume that the ESP makes exactly 0.03 lb/MMBtu on the outlet particulate emission. However, most recent ESP start-ups on P-C boilers have achieved well better than 0.03 lb/MMBtu. Particulate emissions as low as 0.01 lb/MMBtu (approximately10 mg/NM^3) are common on recent start-ups. If the customer has included some conservatism in the specified operating conditions and/or redundant fields, and the ESP vendor has additional conservatism for guarantee, the ESPs will do exceptionally well.

In the case of very low emissions, 0.01 lb/MMBtu (approx. 10 mg/NM^3), the mass emission of $PM_{2.5}$ would be calculated as follows;

0.01 lb/MMBtu * 0.70 = 0.007 lb/MMBtu of $PM_{2.5}$

Note that for this case, the percentage of $PM_{2.5}$ has been increased from about 50 % to 70 % in this outlet penetration because the ESP will collect the coarser fractions in high efficiencies.

This serves to make the particle size smaller as the emissions get lower. Thus, the overall calculated efficiency of this ESP on $PM_{2.5}$ would be;

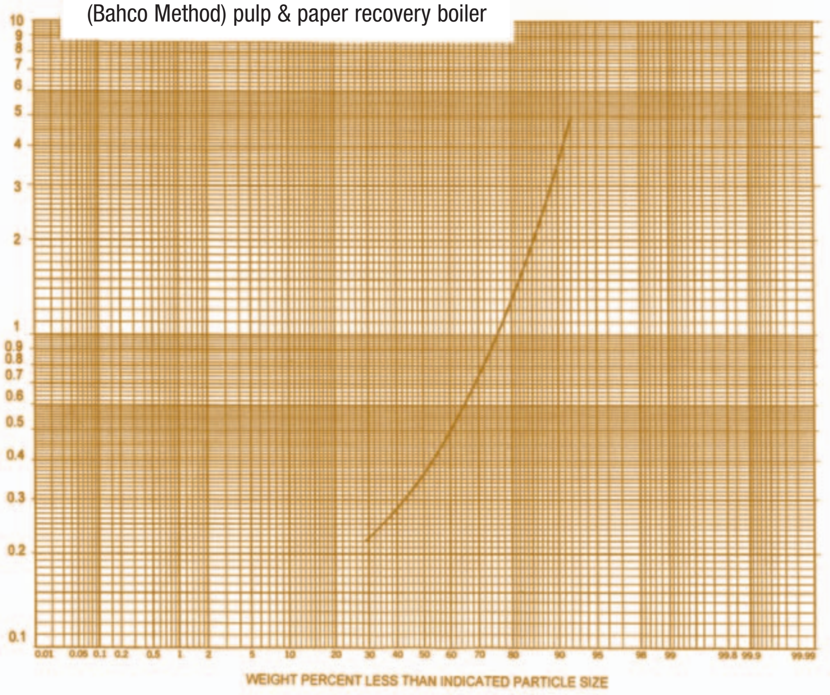
(0.935 - 0.007) / 0.935 = 99.25 % on $PM_{2.5}$

Note that the overall efficiency would be;

(8.5 - 0.01) / 8.5 = 99.88 % on all particulate

Thus these new utility ESPs are demonstrating higher than 99% collection efficiency on $PM_{2.5}$ solid particulate.

FIgure 11: Typical particle size distribution (Bahco Method) pulp & paper recovery boiler



2. *ESPs for Biomass Firing*

Before discussing $PM_{2.5}$ on biomass boilers, it might be useful to discuss PM_{10}. Legislation has already been implemented in some parts of the U.S.A. for biomass fired boilers, which has required PM_{10} emissions to be achieved. However, most biomass has one important chemical characteristic, which is that biomass has almost no sulfur content. Consequently, studies have shown that the contribution of condensibles to particulate mass measurements is very low (using ESP 5 type testing at 248° F probe temperature). Thus, for this specific application, solid particulate very closely approximates atmospheric particulate.

On the above basis, the ESP vendors in the U.S.A. have been able to make guarantees of particulate emissions in a specific particle size range. However, guarantees involving PM_{10} were easy to manage. This is because data on high efficiency ESPs has shown that nearly 100 % of the outlet particulate is less than 10 microns in size. Thus, if a guarantee were required for total particulate less than 0.03 lb/MMBtu (approximately 30 mg/NM^3) and PM_{10} less than 0.02 lb/MMBtu (approximately 20 mg/NM^3), we simply sized the ESP to achieve 0.02 lb/MMBtu of total particulate. We could accept either EPA-5 or EPA-17 testing, because there was little or no sulfuric acid in the flue gas.

The guarantee of $PM_{2.5}$ on biomass firing is a simple extension of the PM_{10} case. There will be little condensibles to worry about, and one simply has to address the fact that some portion of the dust will be less than 2.5 microns and some greater than 2.5 microns. Assumptions would be similar to the pulverized coal case, in that as required outlet emission gets lower assumed fraction less than 2.5 microns would be greater.

One major disclaimer on biomass type firing is that we are discussing bark, sawdust, grape vines, etc. which are natural plant materials. These types of boilers can sometimes get involved with construction debris, creosoted timber, and tire firing. These materials, especially tires, which use sulfur as a vulcanizing agent, do have higher levels of condensibles. The PM_{10} assumptions cannot be extended to that higher sulfur fuels situation.

3. *ESPs for Refinery Fluid Catalytic Cracking Units (FCCU)*

Perhaps the most complicated application for achieving $PM_{2.5}$ emissions would be FCCU. Oddly enough, the problem is not actually in the collection of the solid particulate (silica/alumina catalyst fines). Particulate emissions on this application with dry ESPs have been demonstrated down to 0.001 GR/ACF (approximately 5 mg/NM^3). Similar to other applications, as the solid particulate emission gets lower, the percent of the penetrating particulate less than 2.5 microns becomes greater.

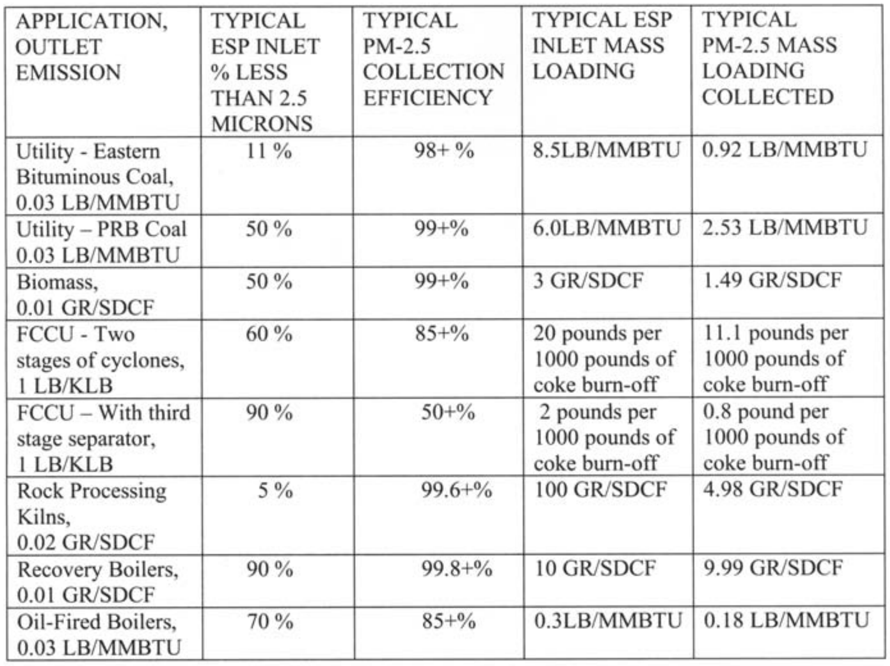
The complication on this application is that there can be a considerable condensibles contribution to particulate measurements. The amount of condensibles depends on test method (EPA 5, 5F, or 17) and probe temperature (180° F, 248° F, 320° F, or process operating F), oil sulfur content, and presence or lack of hydro-treating. So we can have condensibles contributions ranging from near 0 GR/ACF, to as high as 5 or 10 times the amount of solid particulate in the flue gas. So the selection of test method is critical to the ESP design, to the point of forcing the technology to wet scrubbers. If the condensibles present are high and the test method is going to include all or most of the condensibles as particulate, then the use of an ESP is not recommended.

This can make the achieving of total PM or $PM_{2.5}$ a very complicated situation. What happens in some cases is that the condensibles contribution is measured/predicted in advance. Then the ESP has to be sized for solid particulate, so that;

Solid Particulate + Condensibles Contribution =
Total Measured Particulate

Thus, the ESP might be sized for solid particulate emissions well lower than the performance requirement. In this process, the particulate is being pre-cut by a series of two or three cyclones. This removes most of the large particles ahead of the ESP. Then the ESP selectively reduces particle size as well. Therefore, a high collection efficiency ESP on FCCU will have an outlet particle size distribution consisting of very high, >90%, PM$_{2.5}$. Therefore, the conservative approach in this case would be to assume total solid particulate to be equal to solid PM$_{2.5}$.

Figure 12: Application vs. PM$_{2.5}$ collection



APPLICATION, OUTLET EMISSION	TYPICAL ESP INLET % LESS THAN 2.5 MICRONS	TYPICAL PM-2.5 COLLECTION EFFICIENCY	TYPICAL ESP INLET MASS LOADING	TYPICAL PM-2.5 MASS LOADING COLLECTED
Utility - Eastern Bituminous Coal, 0.03 LB/MMBTU	11 %	98+ %	8.5LB/MMBTU	0.92 LB/MMBTU
Utility – PRB Coal 0.03 LB/MMBTU	50 %	99+%	6.0LB/MMBTU	2.53 LB/MMBTU
Biomass, 0.01 GR/SDCF	50 %	99+%	3 GR/SDCF	1.49 GR/SDCF
FCCU - Two stages of cyclones, 1 LB/KLB	60 %	85+%	20 pounds per 1000 pounds of coke burn-off	11.1 pounds per 1000 pounds of coke burn-off
FCCU – With third stage separator, 1 LB/KLB	90 %	50+%	2 pounds per 1000 pounds of coke burn-off	0.8 pound per 1000 pounds of coke burn-off
Rock Processing Kilns, 0.02 GR/SDCF	5 %	99.6+%	100 GR/SDCF	4.98 GR/SDCF
Recovery Boilers, 0.01 GR/SDCF	90 %	99.8+%	10 GR/SDCF	9.99 GR/SDCF
Oil-Fired Boilers, 0.03 LB/MMBTU	70 %	85+%	0.3LB/MMBTU	0.18 LB/MMBTU

4. *ESPs for Cement, Nickel, Lime Mud Kilns*

On kiln applications, there is typically a very coarse/large particle size distribution. At face value, one might assume that these ESPs do not have to collect very many fines. This, since the percent of the particle distribution is less than 2.5 microns, is much lower than other applications. However, in fact, there are quite high levels of fine particulate from kiln applications if the fines are measured in mass concentration, not percent. This is because the ESP inlet dust concentrations from kilns are extremely high. Thus, a smaller percentage of a much larger mass concentration can result in concentrations levels which are as high or higher than some other applications.

Condensibles levels on kilns will be somewhat of a "mixed bag". This is because the fuel for the kiln can range from natural gas, to coal, to oil. There is even disposal of PCB contaminated oils in some kilns. Therefore, care should be taken to evaluate the amount of condensibles, as a significant contribution is possible under some conditions.

5. *ESPs for Pulp & Paper Recovery Boilers*

Of all the ESP applications, this is probably the easiest one to deal with in terms of PM$_{2.5}$ performance. That is because the ESP inlet particle size on this application is extremely fine (See figure 11 on page 12.) The typical mass mean particle size on a recovery boiler ESP is 50% less than 0.35 microns.

As an aside, the fact that ESPs routinely collect these very fine particles on recovery boilers lays to rest any notion that ESPs cannot collect fine particles. As can be seen on figure 11, this recovery boiler particulate is about 90% less than 2.5 microns. ESPs are routinely installed on this application, which achieve 99.9% collection efficiency (total PM) on this very fine particulate. As can also be seen on figure 11, about 25% of the particulate is in the size range less than 0.2 microns. Some researchers in the early or middle parts of the 20th century speculated that ESPs could not collect particles very well in the 0.2 micron range due to particle charging difficulty. Commercial ESPs have not demonstrated this problem that was speculated from theoretical studies. Commercial ESPs are collecting 0.2 micron particles as a matter of course in achieving the very high collection efficiencies required on modern installations.

Returning to the recovery boiler case, the penetration of a high efficiency ESP on recovery boilers should be assumed to be near 100% less than 2.5 microns. Thus, guarantees of total PM and PM$_{2.5}$ would be identical if the test method does not include condensibles. This application does, however, contain some levels of sulfates which could contribute somewhat to a condensable particulate. So care must be taken in designing for $PM_{2.5}$ emissions on recovery boiler ESPs with regard to what test method is required. Test methods which include condensibles will have some condensibles contribution on this application, so both total PM or $PM_{2.5}$ would be somewhat higher than "rocks" only.

6. *Oil Fired Boilers*

Fuel oils contain very low levels of ash, typically 0.1 to 0.3 %. When the oil droplets burn out, the remaining residue is much finer in particle size than say coal combustion. Typical inlet particle size distributions to the ESP will be in the range of 70% less than 2.5 microns. Then, after the ESP removes the larger particles, this application will also drive down toward near 100% less than 2.5 microns on the ESP exit particulate. Therefore, the conservative approach in this case would be to assume total solid particulate to be equal to solid $PM_{2.5}$.

Many fuel oils contain high levels of sulfur. Some, like Pet-Coke, can even range up to 3-6% sulfur in the fuel. These high levels of sulfur translate to high condensibles levels in the flue gas. Test methods should be carefully analyzed as total particulate may have a large contribution from the condensibles fraction.

Some very approximate inferences on solid $PM_{2.5}$ collection efficiencies in dry ESPs can be calculated based upon the above discussions. Of course, every site and ESP collection efficiency will vary widely. This variation will depend on process conditions, ESP age/size, and ESP condition. So the results should be considered trends and not exact predictions. The inferences are summarized in figure 12 on page 13.

Figure 12 shows that the percentage of solid $PM_{2.5}$ in ESP inlet flue gases can vary widely. Depending on process type and upstream pre-collection, the amount of solid $PM_{2.5}$ in flue gases can vary from the range of near 0% to near 100%. However, it is misleading to consider that flue gases with low percentages of $PM_{2.5}$ do not emit much $PM_{2.5}$. Some of the rock processing type kilns have a lot of very large particles, but they also have a considerable level of $PM_{2.5}$. This is because of the very large particulate concentrations in these flue gases. Some other applications, such as FCCU with third stage separator, have almost all $PM_{2.5}$. But due to the pre-collection, the total particulate concentrations are very low. So collecting $PM_{2.5}$ can be critical on both types of applications.

Dry ESPs are able to collect these materials at very high efficiencies, with 99+% collection of $PM_{2.5}$ being very typical. Other applications with lower collection efficiency on $PM_{2.5}$ result because the inlet loadings are very low in general. These low collection efficiencies on $PM_{2.5}$ are not the result of a lesser capability to collect fine material on these applications. Instead, the low efficiencies result from not having much $PM_{2.5}$ mass loading to collect from.

SUMMARY

Dry ESPs have been proven to be highly efficient in reducing fine solid particulate matter (i.e. $PM_{2.5}$), but at a somewhat lower fractional efficiency than the total particulate efficiency. However, care must be taken in clearly understanding the regulated $PM_{2.5}$ requirement. If gaseous components (condensibles) are included as $PM_{2.5}$, alternate technology may be required. Once these factors are clearly understood, specific $PM_{2.5}$ emissions requirements can be designed for and achieved with a dry ESP.

For additional information, contact Robert Mastropietro at robert.mastropietro@gmail.com

WPCA ESP Seminar

FirstEnergy and the WPCA will hold an ESP Technical Seminar at the Hilton Akron Fairlawn in Akron, OH, on November 27-28, 2007. The Chairman will be Doug Hartman from FirstEnergy.

Hilton Akron Fairlawn

3180 West Market Street Akron, OH 44333-3314
Phone: 330-867-5000 www.akronhilton.com
Room rate: $90 (FirstEnergy rate) Reservation cutoff: Nov. 5, 2007

Registration is free to all WPCA members. Non-members who are users of air pollution control equipment can pay the $45 yearly membership fee online and register for the conference at the same time. Go to www.wpca.info starting October first to register and see the preliminary agenda. For further information concerning the seminar, contact Doug Hartman, FirstEnergy, at hartmands@firstenergycorp.com; Scott Williams (WPCA president) at nswilliams@duke-energy.com; or Susan Reinhold, RE, at sreinhold@reinholdenvironmental.com

Selective Catalytic Reduction (SCR) System Being Used in Unique Application

continued from front page

Most cargo ships entering ports depend on electricity they generate themselves with auxiliary diesel engines on-board instead of shore-power because they can control their own equipment and do not have to rely on the numerous types of connections required for shore-power. It is estimated that this SINOx® SCR System will reduce nitrogen oxides at the Port of Long Beach by 100 tons each year while in service for Mitsubishi Cement Corporation. The SINOx® SCR System will be shipping from Argillon Americas in September, 2007, to the Port of Long Beach for installation and commissioning in the near future.

The capture system that covers the exhaust outlet from the ships auxiliary engines is one of the unique components of this SINOx® SCR System. The SCR system, continuous emissions monitoring (CEM), motor control center (MCC) and other related hardware is mounted on a remote-controlled platform (20'W x 50'L) that can move forwards/backwards and side to side. This mobile system allows the SCR system and capture hood to move into the optimum position for any size ship and different exhaust configurations coming into the port. See figure 14 below for more clarification of SCR system.

For more information, contact Randy Sadler at randy.sadler@argillon.com

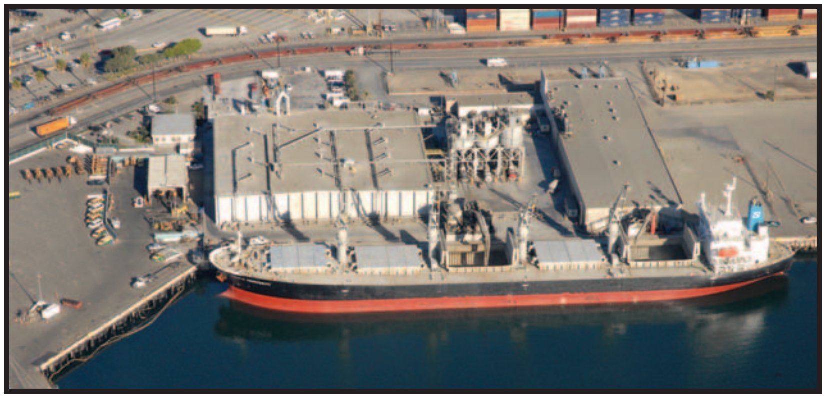


Figure 13: Aerial view of Mitsubishi Cement Corporation Pier at the Port of Long Beach, CA. A typical cargo ship that unloads/loads at this pier.

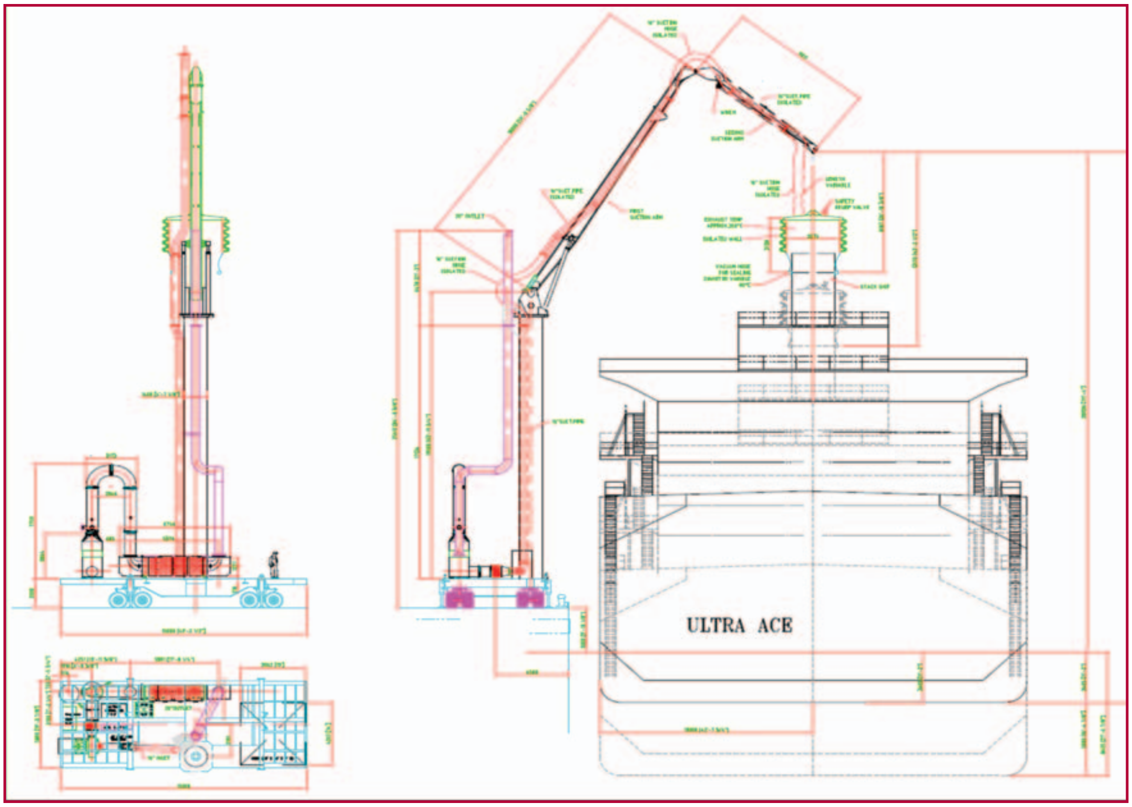


FIgure 14: Side view of SINOx® SCR System showing mobile platform, exhaust capture system over ship's stack.

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