WPCA NEWS
Worldwide Pollution Control Association
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A Bi-Annual Newsletter Sponsored by the WPCA Winter - 2013

Executive Summary (page 1)

Upcoming Regulations to Control Green House Gas Emissions from Existing Electric Generating Units

By Chuck Barlow and Joe Hantz, Entergy

President Obama directed EPA to re-propose Green House Gas (GHG) emission standards for new EGUs which were released on the September 20, 2013 deadline. In the June 25, 2013 initiative, the President also directed EPA to propose guidelines for existing power plants by June 2014 and finalize them a year later. EPA will propose standards for GHG emissions for existing sources under Section 111(d) of the Clean Air Act.

Full Story….

A High Reactivity Hydrated Lime for Challenging Dry Sorbent Injection Applications

By Curt Biehn, Mark DeGenova, Randy Grifford, Richard Zhang, Eric Van Rens, Pat Mongoven, Mississippi Lime

This article discusses a new high reactivity hydrated lime (HRH) for dry sorbent injection applications. Compared to hydrated lime species currently in use, HRH offers better in-flight capture of acidic species. HRH has been evaluated in pilot test facilities and numerous full scale applications. Results from these tests show that HRH is significantly more effective for SO_3 capture than current DSI-grade hydrate.

Full Story….

Sulfite Analyzer for Control of Oxidation Air

By Dennis Laslo, Alstom

The quantity of forced oxidation air in wet flue gas desulfurization absorbers has historically not been controlled as there has not been a continuous means of measuring the sulfite concentration in the tank. Air supplies oxygen for oxidizing the sulfite to sulfate and if the sulfite concentration is quantifiable; the air rate can be controlled. Since it has been difficult to analyze and control the correct air amount, plant operators typically add the full design oxidation air rate to be assured of acceptable sulfite oxidation. The sulfite concentration can now be measured with a patent pending sulfite sensor

Full Story….

WFGD Oxidation Air and Oxidation Reduction Potential

By Shannon R. Brown, Daniel B. Johnson, Babcock & Wilcox Power Generation Group, Inc.

Interest has increased in the measurement and control of wet FGD slurry ORP due to the anticipated federal ELG for wastewater, the regulation of mercury emissions under MATS, and the potential for accelerated corrosion of alloys. Field research has determined that although the control of oxidation air flow is useful for fine control of ORP, the control of oxidation air flow alone will not control a major excursion in ORP. This article provides an in-depth discussion on the response and sensitivity of the dissolved O_2 content and the ORP of WFGD slurry in response to changes in oxidation air.

Full Story….

Continued on next page

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Executive Summary (page 2)

"Fan Test" Helps Design Odor Control Facility

By Matt Fleming, Airflow Sciences Corporation

Sewer odor complaints are an unpleasant problem for large metropolitan areas. A successful odor control technique is to depressurize the sewer system by withdrawing air with a fan; the withdrawn air is then scrubbed to remove odors. This article discusses utilizing a portable activated carbon scrubber while conducting tests to optimize fan flow rates, providing relief to Vancouver, BC residents.

Full Story….

How to Kill Two Pollutants with One Sorbent: Combined Hg and SO_3 Removal using SBS Injection

By Sterling M. Gray, Jim B. Jarvis, Steven W. Kosler, URS Corporation

This article describes a novel approach for mercury control that relies on the injection of a single sorbent to effectively remove SO_3 upstream of the air preheater (APH) which greatly enhances mercury adsorption onto the native "unburned carbon" in the flue gas downstream of the APH. Removal of SO_3 prior to the APH allows for the flue gas temperature exiting the APH to be reduced, which further enhances mercury capture and improves the plant energy efficiency. The co-benefit capture of hydrochloric acid (HCl) and selenium from the flue gas using this approach is also discussed.

Full Story….

Integrating Flue Gas Conditioning for ESP's with MATS Control Strategies

By Richard Miller and Jean Bustard, ADA-ES, Inc.

This article discusses an ESP flue gas conditioning technology which provides an alternative to SO_3 for particle resistivity control. This technology is compatible with sorbents for both mercury and acid gas control, meaning that it does not interfere with activated carbon or be absorbed by alkaline sorbents, and can be part of a plants overall approach to meeting full compliance with MATS. This article also describes the benefits of the technology when used in conjunction with sorbents to meet MATS and presents test results.

Full Story….

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WORLDWIDE POLLUTION CONTROL ASSOCIATION

Upcoming Regulations to Control Green House Gas Emissions from Existing Electric Generating Units

By Chuck Barlow and Joe Hantz, Entergy

On June 25, 2013, President Obama announced initiatives addressing climate change focusing on Green House Gas (GHG) emissions from fossil-fired electric generating units (EGUs). EPA had already proposed standards for new sources in April 2012, but the agency had not yet finalized that rule. The President directed EPA to re-propose GHG emission standards for new EGUs by September 20, 2013. The re-proposed standards were released September 20.

The re-proposed standards propose an emissions limit of:

Gas Turbines –

1. Standard = 1,000 lb CO_2/MWh for "large" facilities
    - >850 MM Btu/hr heat input rating
2. Standard = 1,100 lb CO_2/MWh for "small" facilities
    - ≤850 MM Btu/hr heat input rating

Coal Units - Boilers, IGCC

(also covers oil, gas-fired boilers, etc.)

1. Standard = 1,100 lb CO_2/MWh
    - Rolling 12-month average

The President directed EPA to have these proposed standards for new sources finalized in a year.

The Clean Air Act states that once EPA promulgates emission standards for new sources, they are obligated to promulgate standards for existing sources. In the June 25, 2013 initiative, the President also directed EPA to propose guidelines for existing power plants by June 2014 and finalize them a year later.

EPA will propose standards for GHG emissions for existing sources under Section 111(d) of the Clean Air Act. EPA has little experience in utilizing this section of the Clean Air Act to promulgate regulations, and Section 111(d) is very ambiguous. This will certainly lead to much debate as these rules are promulgated. The text of Section 111(d) can be seen at http://www.law.cornell.edu/uscode/text/42/7411 and is included below.

> **(d) Standards of performance for existing sources; remaining useful life of source**
>
> *(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which*
>
> *(A) establishes standards of performance for any existing source for any air pollutant*
>
> *(i) for which air quality criteria have not been issued or which is not included on a list published under section 7408 (a) of this title or emitted from a source category which is regulated under section 7412 of this title but*
>
> *(ii) to which a standard of performance under this section would apply if such existing source were a new source, and*
>
> *(B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.*
>
> *(2) The Administrator shall have the same authority—*
>
> *(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410 (c) of this title in the case of failure to submit an implementation plan, and*
>
> *(B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 7413 and 7414 of this title with respect to an implementation plan.*
>
> *In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.*

It is certain that both the new source and the existing source proposals will be highly controversial, with a wide variety of stakeholders stating very diverse viewpoints. EPA received 2.5 million comments during the comment period for the proposed standards for new sources released in April 2012. As with any controversial issue that EPA undertakes, it is almost certain that there will be legal challenges along the way. By adhering to the following guidelines when promulgating GHG regulations for existing sources, EPA will have the best chance for successful regulation.

- EPA creates "a procedure" for States to develop "standards of emission performance." EPA should adopt a system that is (i) legally defensible and (ii) circumscribed by a realistic global cost-benefit analysis. Innovation and creativity are great, but the more EPA pushes the legal edge of the 111(d) envelope, the more any rule will be vulnerable to legal challenges.

- Although 111(a) and (d) are ambiguous in many instances (such as the full meaning of "best system of emission reductions" (BSER)), there are some provisions that more clearly limit EPA' or the States' authority (such as certain considerations that must be taken into consideration in setting BSER: cost, non-air impacts, and energy requirements). It is also clear that provisions must be made for the remaining useful life of units and "other factors." It is unclear what may be included as "other factors."

- The central role of the States is also clear and must be preserved. While EPA creates a "procedure" for development of State plans, the States themselves "establish standards of performance." State flexibility must be preserved, especially in the second phase of the program – implementation. In order to take account of significant regional differences in economic growth, fuel sources, and the availability of renewables or energy efficiency, States should retain significant flexibility to determine how the standards can be met (trading, fleet-wide averaging, etc.) and how an implementation plan should be developed.

- States (and emission units) should obtain credit for early action, RPS, and prior GHG programs (RGGI and CA). All megawatts should be treated similarly – in other words, through a long-term baseline period, a long-term compliance period, or the availability of fleet-wide averaging, States and units should be able to take advantage of actions already taken to decrease GHG emissions rates across a fleet, including the use of low and no-emission sources such as nuclear, the shift to more modern gas units, and the use of renewables.

For further information contact Joe Hantz at jhantz@entergy.com

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Joe Hantz is Manager, Environmental Services for Entergy Services, Inc. Hantz manages the Environmental Services group at Entergy that is responsible for Entergy's fossil fleet's compliance with federal environmental requirements. He joined Gulf States Utilities in 1982 and then Entergy in 1994. He has been involved in all aspects of environmental compliance for fossil fueled power plants. Hantz has a bachelor's degree in Environmental Science from McNeese State University.

Congratulations
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"Increasing Energy Efficiency of Existing Units"

(a one day seminar about GHG regs for existing EGUs)

A High Reactivity Hydrated Lime for Challenging Dry Sorbent Injection Applications

By Curt Biehn, Mark DeGenova, Randy Griffard, Richard Zhang, Eric Van Rens, Pat Mongoven
Mississippi Lime Company

Abstract

Mississippi Lime has developed a High Reactivity Hydrated Lime (HRH) for Dry Sorbent Injection (DSI) applications. Compared to hydrated lime species currently in use in the DSI industry (flue gas treatment, FGT), HRH offers better in-flight capture of acidic species such as sulfur trioxide/sulfuric acid and hydrochloric acid. HRH has been evaluated in pilot test facilities and numerous full scale applications. Results from these tests show that HRH is significantly more effective for SO_3 capture than current DSI-grade hydrate. In addition, HRH has successfully allowed plants to meet 2015 MATS regulations for HCl in evaluative full scale testing. The improved reactivity of HRH offers benefits to applications facing challenges such as high level pollutant removal or short residence times.

Introduction

Flue gas treatment has become a necessity for many coal-fired utilities and industrial operations due to increasingly tighter air quality standards. Plants with wet Flue Gas Desulfurization (FGD) systems may require an additional mechanism to control secondary plume emission of fine sulfuric acid droplets. Halides in fossil fuels are combusted and form their corresponding acid in the flue gas emissions. These acids also contribute to corrosion of internal equipment or, uncaptured, pollute the air via stack emissions.

While many systems already exist for SO_3/H_2SO_4 for eastern bituminous coal-fired units equipped with SCRs and wet FGD, the 2015 MATS regulations will require additional strict control of emissions. Units without current FGD controls may elect to control hydrogen chloride emissions to meet the maximum 0.002 lb HCl/mmBtu regulation. Units requiring mercury control to meet the 2015 MATS may also need a mechanism to mitigate SO_3 from the flue gas prior to carbon injection, as SO_3 has been proven to adsorb onto carbon and reduce its capability for controlling mercury.

Alkali species are typically used to neutralize the acidic components of the flue gas, typically through the use of Dry Sorbent Injection. The sorbents are prepared as a fine or coarse powder and transported to the user's site. Dry sorbent injection systems pneumatically convey the sorbent as a fine powder-air dispersion in the duct. The dry sorbent neutralizes SO_3/H_2SO_4, HCl, and/or HF.

The most common sorbent used is hydrated lime. Hydrated lime reacts with SO_3 to form calcium sulfate and the halogenated acids to form the corresponding calcium salt.

$$SO_3 + Ca(OH)_2 \text{ -> } CaSO_4 + H_2O$$
$$H_2SO_4 + Ca(OH)_2 \text{ -> } CaSO_4 + 2H_2O$$
$$HCl + Ca(OH)_2 \text{ -> } CaCl_2 + H_2O$$
$$HF + Ca(OH)_2 \text{ -> } CaF_2 + H_2O$$

Hydrated lime systems are proven successful in many existing full-scale operations. These systems operate full scale and throughout the year to provide Utility customers with a dependable, cost-effective means of acid gas mitigation. The most effective hydrated lime sorbents for Dry Sorbent Injection have high (>20 m^2/g) BET surface area.[1] These sorbents offer good conveying characteristics and good dispersion in the flue gas which is necessary for high removal rates. Use of a higher quality source of hydrated lime allows the Utility better stoichiometric ratios than early attempts using lower quality hydrated lime originally targeted for other industries such as wastewater treatment, construction, asphalt, etc.

Hydrated lime possesses many advantages over other alkali species used in DSI. Hydrated lime is typically available in pneumatic truckload quantities relatively close to the plant site. Hydrated lime does not require onsite milling, so less capital is required for new systems. Ongoing maintenance and parasitic power is lower with hydrate than for sorbents that require milling. Hydrated lime is not extremely sensitive to moisture, which reduces the requirements for conveying air quality. Hydrated lime forms stable byproducts when reacted in the flue gas, so strict temperature and stoichiometric controls are not a necessary. Finally, the ash byproducts formed when using hydrated lime are stable and non-leachable calcium salts that generally are not a problem for landfills.[2]

Challenges for Hydrated Lime for Acid Gas Mitigation

As with any DSI sorbent, challenges do exist for hydrated lime DSI. Some challenges are common to all dry sorbents and some are particular to calcium.

High Level Removal of Pollutants

Many systems aimed at SO_3 mitigation were designed to target a removal level down to 5-8 ppm SO_3 at the stack. That level is satisfactory to control the visual appearance of the stack emissions; however, several recent regulatory decisions have pushed for stack SO_3 emissions at levels < 2 ppm. At this point, power plants are faced with capital and/or maintenance-intensive systems such as milled or liquid sodium sorbents, baghouses, and/or wet ESPs.

The implementation of the MATS rule in 2015 requires Utilities and Industrial boilers to meet strict limits for HCl emissions (0.002 lb/mmBtu and 0.022 lb/mmBtu, respectively). Units without scrubbers will need to utilize DSI to meet those requirements.

Short Residence Time

Systems with short residence time (< 1.5 sec) prior to particulate collection, wet FGD, or secondary sorbent injection (activated carbon for example) are particularly vulnerable to reactivity issues related to inability to fully disperse hydrated lime sorbent throughout the flue gas. For all dry sorbents, short residence times generally require higher stoichiometric ratios of alkali to acid.

	Reactivity	**Surface Area**	**Pore Volume**
High Reactivity Hydrate	**4 sec**	**21.3 m²/g**	**0.10 cm³/g**
Hydrated Lime FGT	**27 sec**	**21.5 m²/g**	**0.09 cm³/g**
Commodity Hydrate	**56 sec**	**15 m²/g**	**0.05 cm³/g**

Figure 1: Comparison of hydrated limes in reactivity test

For sites treating for mercury removal, it is economically prudent to remove most SO_3 prior to injecting the mercury sorbent. Left untreated, SO_3 will adsorb onto activated carbon and reduce its effectiveness.[3] Thus, the use of a more reactive hydrated lime will provide for lower SO_3 levels in the flue gas when mercury sorbent is injected.

Controlling SO_3 prior to the air preheater (APH) offers many advantages to utilities. In addition to earlier corrosion control, the ability to drop flue gas SO_3 levels at the APH inlet can reduce APH fouling attributed to ammonium bisulfate (ABS) formation. As a result, unit downtime occurrences for APH cleaning are reduced. In addition, lower SO_3 flue gas levels can allow the unit to operate at a lower APH outlet temperature, improving heat rate.[4,5]

Resistivity Effects on Ash[6]

Most current Utilities that require acid gas mitigation utilize an electrostatic precipitator (ESP). Many existing ESPs were designed and installed prior to dry sorbent injection, so the added particulate as the result of DSI was not factored into ESP capacity. Calcium reagents can increase the resistivity of the ash that collects on the ESP plates. If the resistivity is increased too much, the ESP plates will not capture ash from the flue gas, resulting in increased opacity and particulate content of the flue gas exiting the ESP. The use of a more effective sorbent for SO_3 or HCl means that less hydrated lime will be required to control emissions, thus reducing the particulate loading on the ESP.

Experimental

Mississippi Lime set out to develop a next generation hydrated lime that would handle the new challenges of the DSI industry. Our target was to make a product that would react faster, thus providing for more in-flight capture and better overall removal of pollutants. Our Research and Development team identified target properties of the new hydrate. Using a laboratory screening test, we identified the strongest candidate for additional testing. The new hydrate showed superior reactivity versus Mississippi Lime's Hydrated Lime FGT and other hydrated limes. This is important because the FGT product is a proven product in the DSI industry with a well-established record of success[7,8]. See Figure 1.

Lab Scale Testing

Evaluation of reactivity at a laboratory scale provides a good comparison under controlled conditions. While these conditions may not be exactly scalable to Utility applications in the field, the lab test serves the purpose of comparing the performance aspects of the existing product to that of the test product. For comparison of the hydrated lime samples, Mississippi Lime utilized Thermal Gravimetric Analysis (TGA) conducted at outside laboratories. One program evaluated TGA performance under high temperature conditions with SO_2 as the acid gas. The second program evaluated the hydrated lime sorbents' abilities to neutralize HCl at lower temperatures. In both cases, High Reactivity hydrate exhibited clearly superior reactivity toward the target pollutant compared to Hydrated Lime FGT.[9]

Pilot Scale Testing

Promising results at the lab scale led to interest in pilot scale testing of the new hydrate. Two programs were conducted: an evaluation of SO_3 mitigation at the Southern Research Institute in Birmingham AL and an evaluation in low temperature HCl mitigation at the Babcock & Wilcox pilot plant in Barberton OH. Both pilot plants have been previously described. [10,11]

SO_3 Removal

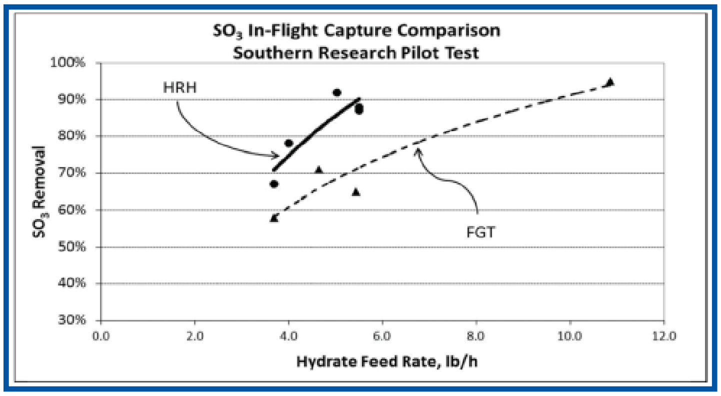

Figure 2: Comparison of SO_3 removal capabilities of FGT and HRH in a pilot scale boiler

The SO_3 test was conducted on Southern Research's 1 MW equivalent pilot plant firing eastern bituminous coal. Additional SO_3 was supplied to the flue gas to provide a steady concentration throughout the test runs. Hydrated lime was injected into the flue gas through a single nozzle. Sampling for SO_3 concentration (Method 8A) was performed at the baghouse inlet location. Comparative results between HR and FGT (Figure 2) show the benefit of HRH: higher reduction of SO_3 at equivalent hydrate feed rates

HCl Removal

A second pilot scale test was conducted at the Babcock & Wilcox pilot facility. Our program utilized simulated flue gas containing SO_2 and HCl at varying concentrations. Using simulated flue gas allowed a direct comparison between FGT and HRH under controlled conditions. Hydrate performance for HCl removal was similar to that shown for SO_3; HRH showed better in-flight and overall removal (baghouse outlet) when compared to FGT. See Figure 3.

Full Scale Evaluations

With performance proven at lab and pilot scale, we next moved to full scale demonstrations of HRH's advantages over FGT. Several examples are provided below.

SO_3 Removal

Example 1: A large (> 300 MW) Unit firing bituminous coal has a permanent system for feeding hydrated lime for SO_3 control. In this test, HRH gave lower SO_3 levels at

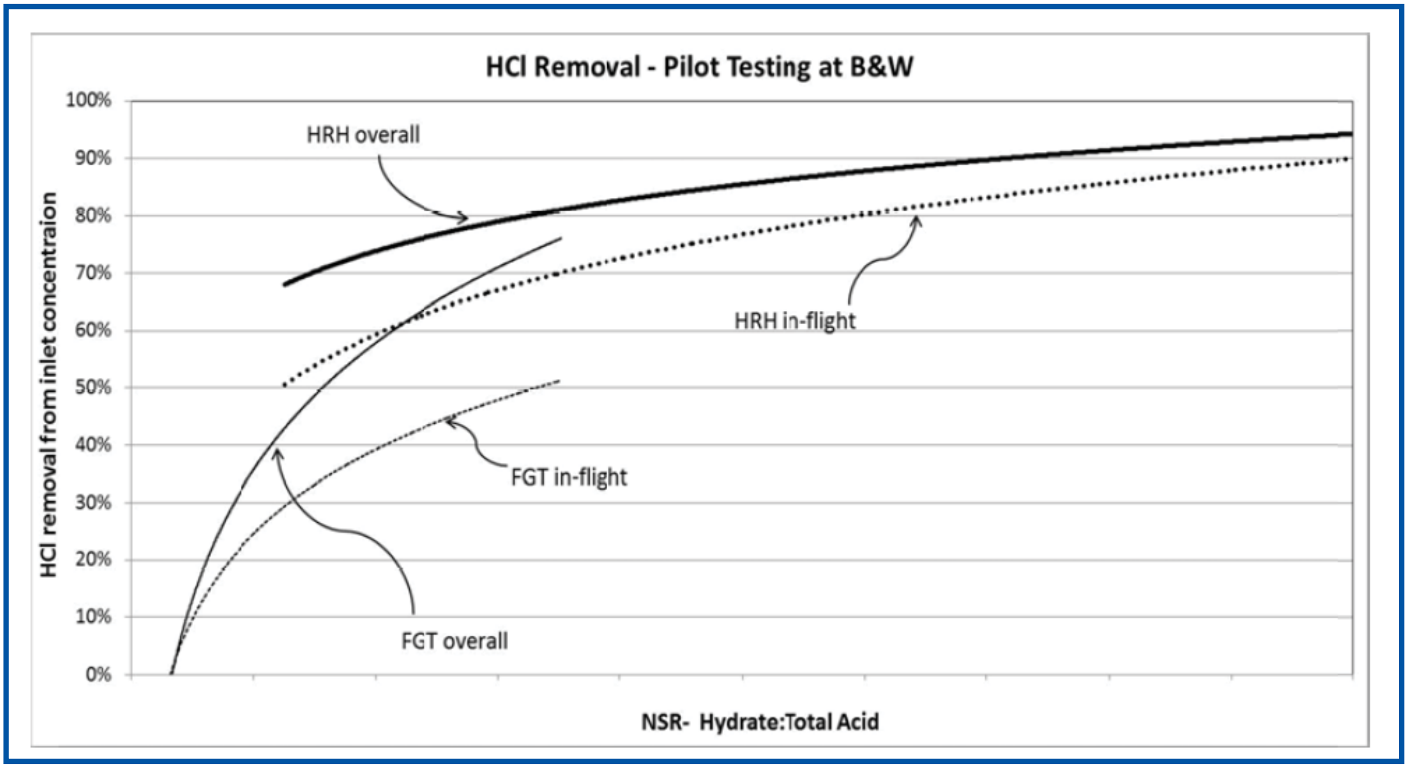

Figure 3: Comparison of in-flight and overall HCl capture of FGT and HRH with simulated flue gas

equivalent treat rates to FGT. Samples were measured using controlled condensation at the FGD inlet.

FGT: 5 - 6 ppm SO_3
HRH: < 2 ppm SO_3

Example 2: Another large (> 300 MW) unit using bituminous coal utilized a temporary injection system for SO_3 emission control. The test compared hydrated lime feed rate necessary to achieve low level (< 3 ppm) SO_3 emissions. The Unit required significantly less HRH than FGT.

FGT: 2,500 lbs/hr to achieve SO_3 emissions < 2 ppm
HRH: 1,800 lbs/hr to achieve SO_3 emissions < 2 ppm

Example 3: A very large (> 500 MW) Unit using bituminous coal evaluated both types of hydrated lime with injection at the SCR outlet. Significantly less HRH was required in order to achieve similar SO_3 levels at the inlet to the Wet FGD.

FGT: 4,400 lbs/hr to achieve SO_3 emissions < 2 ppm
HRH: 3,200 lbs/hr to achieve SO_3 emissions < 2 ppm

Example 4: A smaller (< 300 MW) Utility boiler equipped with an SCR was interested in controlling SO_3 prior to the APH to try and reduce the potential for Ammonium Bisulfate (ABS) treatment. Both FGT and HRH were evaluated at similar treat rates under similar boiler conditions. HRH exhibited better in flight capture than FGT when measured with a Breen AbSensor probe located at the Air Preheater outlet with hydrate injection at the SCR outlet. See Figure 4.

Example 5: A large (> 300 MW) Utility boiler operated an extended campaign (> 5 days) of each hydrate, and SO_3 removal rates were determined at various hydrated lime feed rates. The chart shown in Figure 5 depicts SO_3 removal rates when the unit was operating at high load conditions. The example shows HRH's improved capability for increased SO_3 removal in a full scale application. See Figure 5.

In a similar test program, both hydrated lime types were used for SO_3 mitigation and removal rate was measured via controlled condensation testing. Based upon this test, the site has the potential to use up to 30% less hydrated lime with HRH while maintaining similar control to FGT. See Figure 6.

Example 6: A large (> 300MW) Utility boiler equipped with an SCR was interested in controlling SO_3 prior to the APH inlet in order to reduce instances of forced outages for APH cleaning due to ABS buildup. Several hydrated lime feed rates were evaluated at varying loads. Using Breen monitors at the APH inlet, the results showed that HRH has a significant advantage over FGT in this application, with capability to reduce SO_3 levels by over one-half of those experienced when using FGT. The same relationship was observed at reduced load conditions. See Figure 7.

Additionally, HRH has been campaigned for extended periods (2-8 weeks) in DSI applications without issues in the pneumatic conveying/dry sorbent injection system.

HCl Removal

Several test programs have been completed using HRH to achieve HCl reductions necessary to meets the upcoming 2015 MATS requirements. Due to the nature of many of the test programs, the host Utility typically chose to test only one hydrate type in order to control costs of the testing program. Highlights of testing since 2012 are provided in Figure 8 on page 8.

Results and Discussion

High Reactivity Hydrated Lime offers many advantages to sites currently using or planning to use DSI. Throughout its development, HRH was targeted for applications requiring fast reactivity and high level removal of acidic pollutants such as sulfuric acid mist and/or hydrochloric acid. The optimistic results of bench and pilot scale testing have borne themselves out in the extensive full scale testing.

Type	Feed Rate	SO_3 (est.)	Dew Point (est.)	Comment
FGT	475 lb/hr	>45 ppm	>305 °F	High potential for ABS formation
	800 lb/hr	< 2 ppm	< 170 °F	Little/no SO_3
HR	475 lb/hr	~ 20 ppm	~290 °F	Reduced potential for ABS formation
	800 lb/hr	< 2 ppm	< 170 °F	Little/no SO_3

Figure 4: SO_3 reductions experienced with hydrated lime injection at the SCR outlet

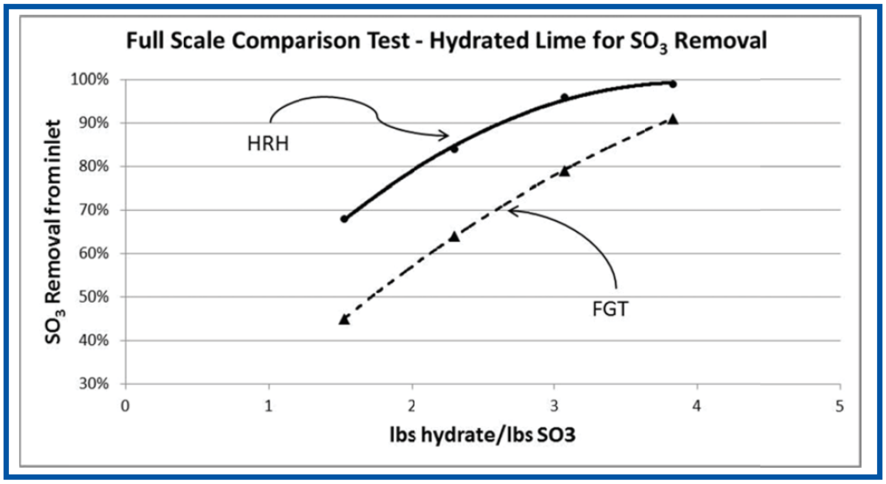

Figure 5:
Full scale comparison of SO_3 removal performance of FGT and HRH (averaged data).

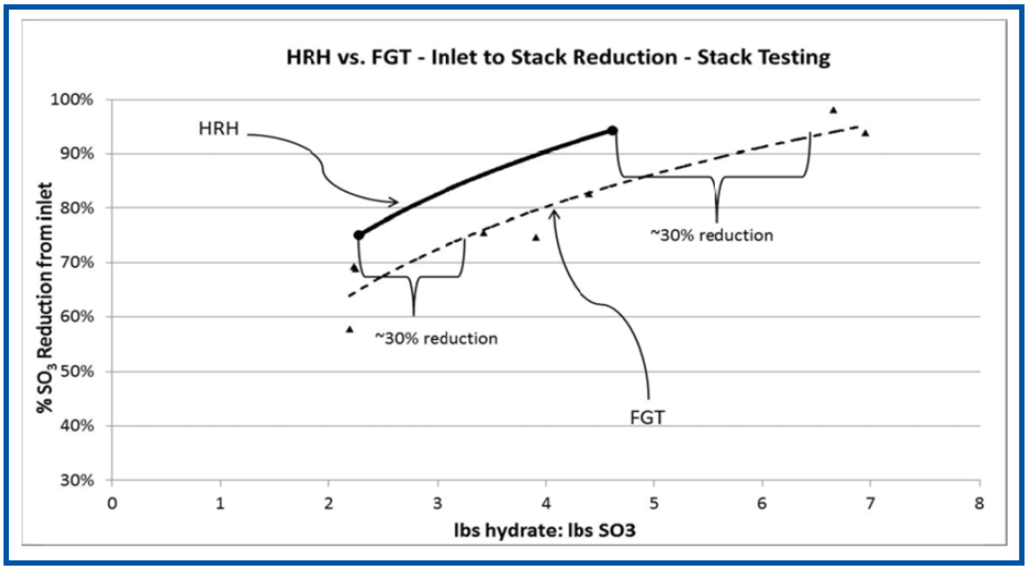

Figure 6:
Full scale comparison of SO_3 removal performance of FGT and HRH (stack testing).

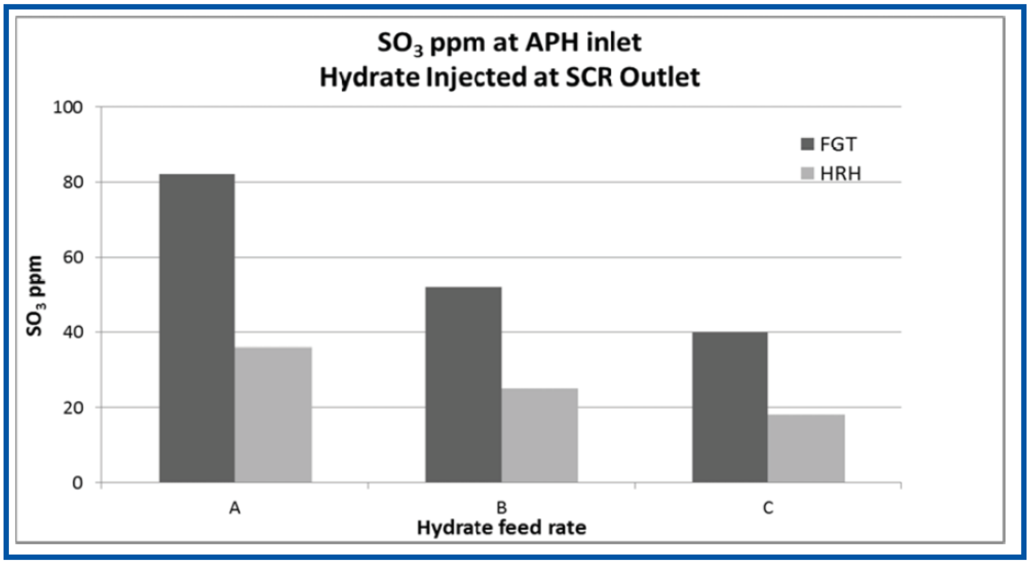

Figure 7:
Pre-APH in-flight reduction of SO_3 with hydrated lime injection at the SCR outlet.

Lower stack emissions of sulfuric acid/SO_3 or HCl

Prevailing opinion in the DSI industry was that, in order to reliably achieve very low stack emissions for sulfuric acid mist (< 3 ppm), a site must consider milled trona or liquid sodium bisulfate (SBS). While those technologies are in practice, there can be substantial maintenance costs associated with either of those systems. There is also risk associated with byproduct formation in ductwork or rising costs of disposal of ash containing soluble sodium compounds and the issue of increased leachability of heavy metals. With HRH, Utilities have a calcium-based option for DSI installations requiring reliable, high level removal of pollutants. This option does not need mills to meet desired performance nor does it need elaborate dilution and injection grids. HRH can be transported in conventional pneumatic conveying equipment typical of the DSI industry.

The results shown in the Experimental section prove that high removal rates of SO_3 or HCl are easily attainable with HRH. This product has been used successfully in units requiring Sulfuric Acid Mist emission levels of < 2 ppm where a conventional hydrated lime was unable to reliably meet those performance levels.

Challenging System – Faster, In-flight Capture

Several examples show the improved in-flight capture possible with HRH. From the initial program at Southern Research Institute, where over 20% more SO_3 was removed at the baghouse inlet location, to later full scale examples where significantly less SO_3 was present at the APH inlet when using HRH at the SCR outlet, testing data proves that HRH reacts faster than FGT. In Example 6, the use of HRH at the SCR outlet reduced the SO_3 content by over one-half the level when using FGT at similar treat rates. This performance improvement can allow the unit to maintain APH cleanliness for longer periods and reduce downtime for cleaning. Lower acid dew points at the APH inlet can also allow units to capture more heat in the APH and improve heat rate, offering a substantial savings opportunity.

The improved reactivity offers benefits to applications where Utilities are co-injecting a mercury sorbent and want to maximize SO_3 removal prior to injection of that sorbent. SO_3 will be scavenged by activated carbon at the detriment of mercury capture. Hence, a hydrated lime that captures more SO_3 in-flight offers an economic benefit to units mitigating mercury with activated carbon. In some cases, HRH may be a regulatory necessity. One test program aimed at mercury mitigation for 2015 MATS was unable to meet the limits with existing hydrate lime options. The program used HRH and was easily able to meet the 2015 MATS levels for mercury.

Coal Type	Particulate Collection	HCl reduction	Hydrate Total Acid NSR	Comment
Western/PRB	BH	>95%	0.80	Easily achieved MATS
App. Coal	BH	>99%	3.0 – 4.0	Easily met MATS Also 40-50% SO_2 reduction
Western/PRB	ESP	>80%	0.50	Easily achieved MATS
Waste	BH	>96%	1.5 – 2.2	Near MATS
High Cl	ESP*	90%	0.7	MATS achieved

*very marginal ESP with <1.5 sec residence time

Figure 8: DSI Test Programs using HRH for HCl mitigation (all units >100 MW)

SO_3 Control Level	Product	Wt. ratio lbs. hydrate/lbs SO_3	Feed Rate lbs/hr	Annual Usage 85% OST	HRH Savings Tons/year
75% removal	FGT	3.25	1,000	3,725 tons	1,125 tons
	HRH	2.27	700	2,600 tons	
95% removal	FGT	6.50	2,000	7,470 tons	2,150 tons
	HRH	4.55	1,400	5,230 tons	

Figure 9: Comparison of annual hydrate usage for different SO_3 removal levels

Potential for Lower Annual Sorbent Costs

The cost of hydrated lime is fairly freight sensitive; delivered costs are a function of product and freight costs. While HRH has a price premium over FGT, for many applications the total annual delivered costs will be reduced since less material will be required to maintain similar emissions levels.

Using the Unit described in Example 5 as a reference, the hydrated lime requirement reductions shown in Figure 9 represent approximately 47 and 89 less truck shipments annually. In addition to lower annual freight costs, use of HRH should provide for reduced truck traffic in plants, less fly ash, and less fly ash disposal costs.

Conclusion

While current DSI-grade hydrated lime sources like Mississippi Lime's FGT are capable performers, improved hydrates like HRH offer additional advantages. Regulations continue to tighten on coal-fired generation and the market needs a reliable, high performance, cost-effective hydrated lime for 2015 and beyond. By building on the benefits of hydrate for DSI – ash friendliness, simple injection systems, stable by-product – HRH is a next generation sorbent for mitigating SO_3 and HCl.

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[1] *Benson, L.; Thomas M. (2005 November). Use of Alkaline Earth Hydroxides for Reduction of Plume Visibility in Coal-fired Power Plants. Paper presented at Power-Gen International Conference, Las Vegas NV.*

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Curt Biehn is Manager, Marketing & Technical Services for Mississippi Lime Company. He has been with Mississippi Lime since 2008, focusing on the Utility Industry and Dry Sorbent Injection for Air Pollution Control. Curt works with utilities and equipment companies to advance the understanding of hydrated lime for SO_3 and HCl control, injection location optimization, and conveying system optimization. Curt holds a B.S. degree in Chemistry from Southern Illinois University – Edwardsville and a M. S. in Organic Chemistry from The Ohio State University. Prior to joining Mississippi Lime, Curt worked in the specialty chemical industry in several roles, including Technical Services, Operations, Quality Management, and Applications Development.

Sulfite Analyzer for Control of Oxidation Air

By Dennis Laslo, Alstom

Sulfite Sensor

The quantity of forced oxidation air in wet flue gas desulfurization (WFGD) absorbers has historically not been controlled as there has not been a continuous means of measuring the sulfite concentration in the tank. Air supplies oxygen for oxidizing the sulfite to sulfate and if the sulfite concentration is quantifiable; the air rate can be controlled. Since it has been difficult to analyze and control the correct air amount, plant operators typically add the full design oxidation air rate to be assured of acceptable sulfite oxidation. Thus, the operating air rate is almost always an excess amount of air which results in wasted power and possibly other negatives. The lost revenue from wasted power can be substantial over an extended time period.

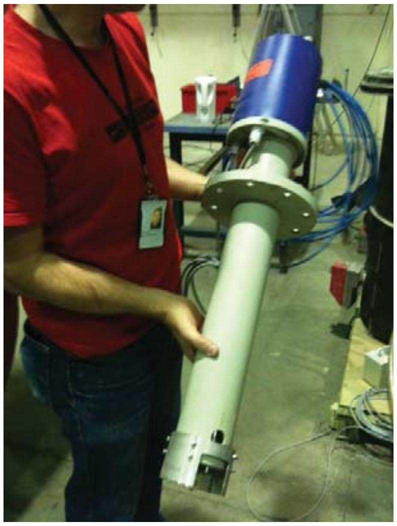


Figure 10: Alstom Sulfite Analyzer

The sulfite concentration can now be measured with a patent pending sulfite sensor which Alstom developed in conjunction with a major university. The concept has been successfully demonstrated on a pilot scale in Alstom's laboratory and on full size WFGD absorbers at two utilities – one a high sulfur Eastern coal installation and another, a western utility plant burning low sulfur coal. A long term reliability run of 6 months operation was recently completed successfully at the high sulfur coal utility.

The New Sensor

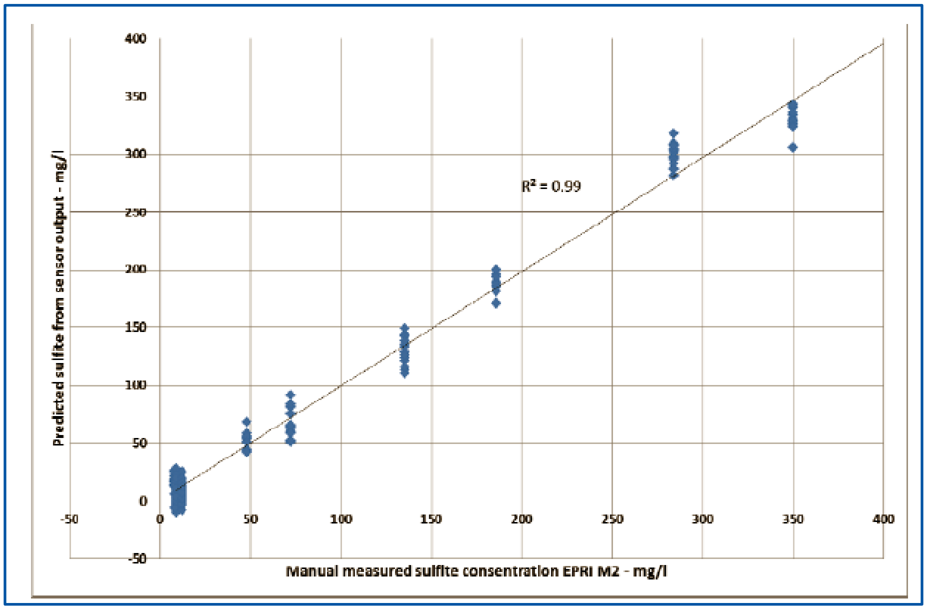
The components of the sensor are simply a probe and a housing. The housing includes a smart board which has the proprietary software necessary for calculating the correct sulfite concentration, and can also collect other measured data, such as pH, oxidation reduction potential (ORP) and liquid temperature. One measurement including calculations takes approximately 13 seconds to complete.

Figure 11: Alstom's sulfite sensor installed on a western U.S. WFGD site

Performance

The test results shown below are from the sulfite sensor

Figure 12: Analytical sulfite measurements vs analyzer predicted values



on the WFGD behind a 1300MW boiler burning high sulfur coal. The graph shows the correlation of the sulfite analyzer with measurements using standard analytical techniques. Sulfite concentration was initially low at the plant and steadily increased by decreasing oxidation air from the oxidation air blowers (the blowers at the plant have a turn down capacity of about 50%.) and sometimes also turning them off completely. The calibrated sensor predicted far better than expected matching analytical results almost perfectly.

Sulfite Control

Control of oxidation air to a sulfite concentration set point is the next phase of Alstom's development program. By controlling oxidation air to a fixed set point of sulfite, a utility can save power associated with the force oxidation air compressors. In addition to energy savings though, another major advantage of controlling oxidation air is the effect on the absorber ORP. High ORP has been linked to excessive mercury reemissions, poor selenium capture in the waste water treatment, accelerated alloy corrosion, and even problems with bacteria in bio-reactors. Some have tried control of oxidation air using ORP probes. ORP does not always respond directly with sulfite concentrations and accuracy at low sulfites is poor. Also, interferences with ORP are common and sometimes unknown. Controlling oxidation air with the Alstom sulfite sensor, can keep ORP at low values and can help to minimize or even resolve one or more of the aforementioned issues.

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Dennis Laslo is Product Engineering Manager with global responsibility for limestone gypsum and seawater wet flue gas desulfurization (FGD) and mercury capture technologies for Power. He has been at Alstom for over 23 years in both engineering and R&D of FGD and carbon capture systems and has authored many papers and holds numerous patents in the air pollution field. Laslo has a BS in Chemical Engineering from Drexel University.

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WFGD Oxidation Air and Oxidation Reduction Potential

By Shannon R. Brown and Daniel B. Johnson, P.E., Babcock & Wilcox Power Generation Group, Inc

In recent years, electric utilities' concerns over Wet Flue Gas Desulfurization (WFGD) and Waste Water (WW) Effluent chemistry have increased. The phase partitioning of several metals of concern with regard to the anticipated federal Effluent Limitation Guidelines (ELG) and/or regulated metals under new federal Mercury and Air Toxics Standards (MATS) rules, within the WFGD absorber slurry and resultant WW, is controlled by both pH and oxidation reduction potential (ORP) values.

Recent research by Babcock & Wilcox Power Generation Group, Inc. (B&W PGG) also has shown that the potential for aggressive manganese induced under-deposit corrosion of the duplex stainless steel alloys in a WFGD environment is a function of the ORP level of the slurry.

Due to these two areas of concern, utilities have expressed great interest in measuring and controlling WFGD slurry and WW ORP levels.

In a limestone force-oxidized (LSFO) WFGD unit, control of the oxidation air is a primary concern due to the formation of the sulfites and potential for sulfite scale formation or limestone blinding. Ensuring the maintenance of adequate oxidation levels is a concern for mitigation of such concerns.

However, a small concentration of sulfites within the WFGD absorber slurry is not detrimental to scrubber chemistry, and may be beneficial in some situations. Since sulfites are a reducing species, they can react with strong oxidants within the slurry to form gypsum. One thought is that excess sulfites in the WFGD environment will act as a buffer for ORP, thereby helping to regulate the units in case of ORP excursions.

Within the last year, B&W PGG has conducted field trials at several units and found that while the use of oxidation air turndown to control ORP is useful as a fine control method for steady operation, a major ORP excursion will overwhelm a fine-tuned system that solely relies on excess sulfite levels for ORP control.

ORP is a measure of the potential for a chemical species either to acquire or release electrons. This potential is commonly measured by an ORP probe in millivolts (mV), which can be done in-line under process conditions. Readings of positive potential are indicative of an oxidizing system, whereas negative values for the potential indicate a reducing system.

The ORP of WFGD slurry and effluent is driven by the presence or absence of strong oxidizers. Many operating WFGD units run at a moderate ORP range of about 100-300 mV, generally holding a rather stable voltage reading over time. Such units often have oxidizer concentrations within the slurry below 200 ppm.

Other units operate at high ORP profile, above about 500 mV. Slurries with high ORP contain a high concentration of strong oxidizer(s), such as persulfate, peroxymonosulfate and/or hypochlorate. Strong oxidizers are measured at total concentrations over 1000 ppm in WFGD absorber slurry samples exhibiting high ORP. Units are observed to swing

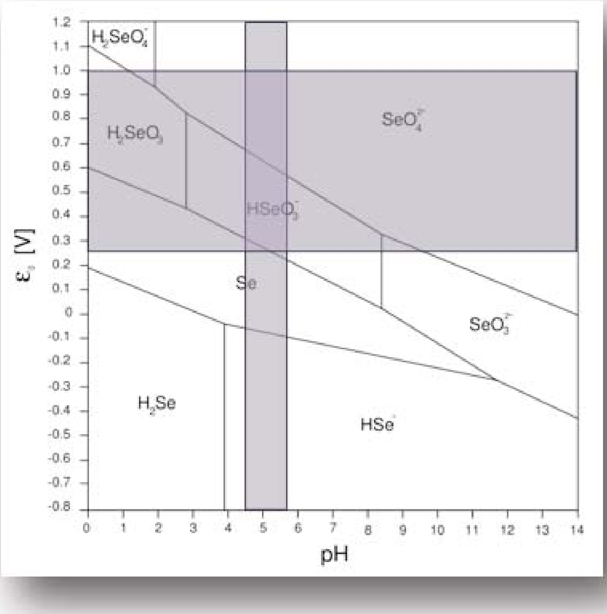

Figure 13: Pourbaix diagram for selenium

from one process condition to the other (high vs. low ORP), but few, if any, hold at an intermediate value for an extended period of time. This information is important with regard to some ELG metals of concern because, using knowledge of WFGD slurry or WW ORP, one may predict the dominant oxidation state for the constituents within that solution. For many metals, solubility is a function of the oxidation state.

Therefore, once the preferred oxidation state for a given chemical species in a solution is known, one can infer the dominant phase in which that species may be. The electrochemically preferred states of a given material at equilibrium are found within the Pourbaix diagram for the chemical species and presented as a function of pH and electrochemical potential. As an example, Figure 13 provides the Pourbaix diagram for selenium, with common LSFO WFGD scrubber slurry pH and electrochemical potential ranges highlighted in purple.

During testing at one field trial in the fall of 2012, B&W PGG was allowed to vary the oxidation air flow into one LSFO WFGD unit, with the sister unit operating as a control unit. Oxidation air flow rate was parametrically changed to three levels: minimum operation, normal operation and maximum flow rate. Slurry dissolved oxygen was measured at each flow rate.

Figure 14 shows the averaged dissolved oxygen (DO) concentration for each of the different blower capacity settings; the error bars are one standard deviation in length in each direction. Changes were made to Unit A. Unit B results served as a baseline for comparison. Effectively, the DO content of the slurry was indistinguishable at all conditions tested.

The turndown of the oxidation air to the minimum allowable value established by the compressor vendor, approximately 45% of full load, demonstrated no appreciable change in dissolved oxygen. The full load testing of the oxidation air compressor had similar results with no apparent change measured in dissolved oxygen.

Since the absorber slurry was operating at the saturation limit for dissolved oxygen, increasing the oxidation airflow merely resulted in more air passing through the system rather than dissolving in the slurry. In fact, results for dissolved oxygen measurements at minimum turndown and at maximum flow rate were indistinguishable (Figure 14), with close averages and falling within the standard deviation of each other. Further, no change in ORP was observed in conjunction with any of these changes in the oxidation air flow rate.

Based on this data, one can infer that increasing oxidation airflow does not increase WFGD slurry ORP once saturation

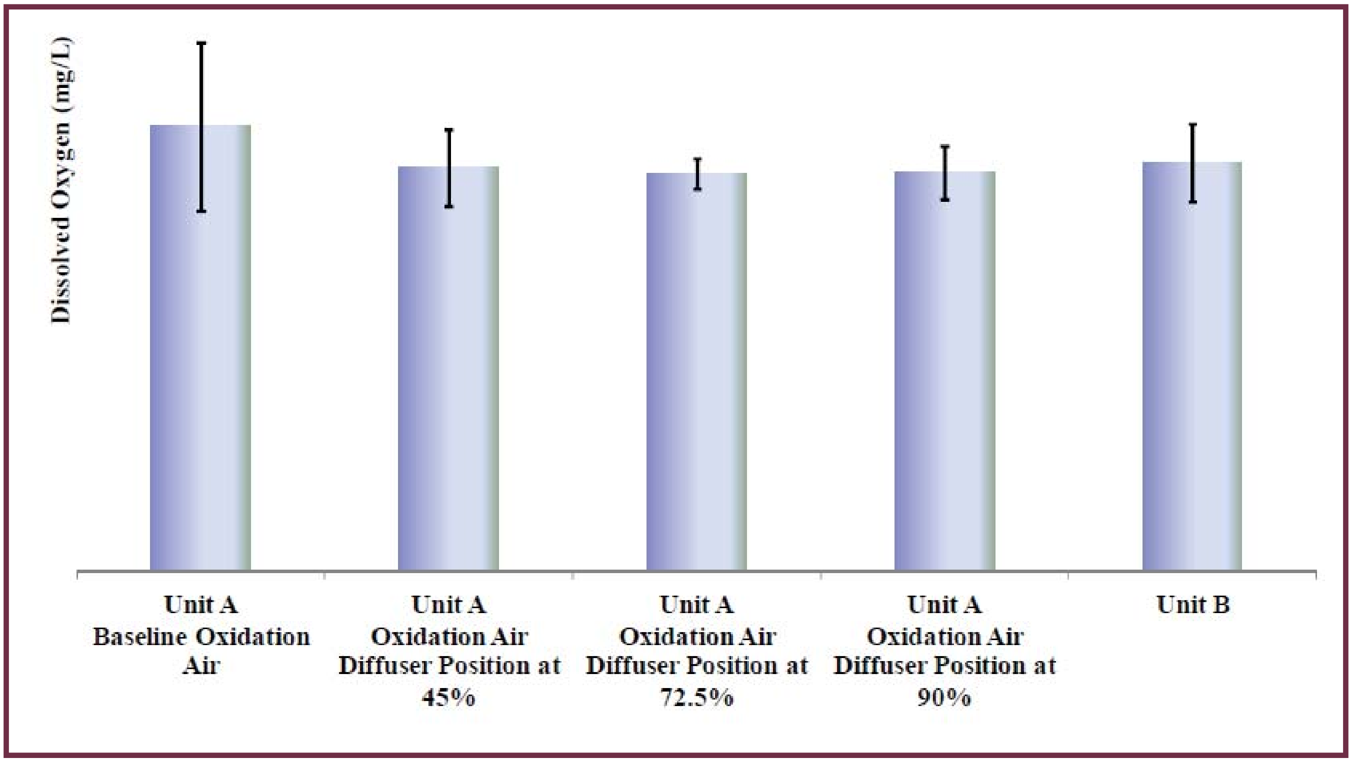

Figure 14: Average dissolved oxygen consentrations for measured in WFGD absorber slurry

of dissolved oxygen has been reached; excess oxidation air does not add to the ORP levels in the WFGD slurry.

This test was repeated on a similar unit, running at full load. During this testing, the oxidation air was turned off completely for a brief time period, which allowed the measured ORP in the WFGD slurry to change from 160 mV to 80 mV. Once the oxidation air was reintroduced back into the system and dissolved oxygen saturation was reached, the ORP returned to the nominal value around 160 mV.

B&W PGG believes that a rapid change of 80 mV in measured ORP value may be possible with variations in oxidation air flow and slurry sulfite levels, as the dissolved oxygen in the slurry decreases. This means that under-oxidation is a possible method for lowering of ORP within a tight range and that, as stated previously, over-oxidation is not possible once the dissolved oxygen saturation is reached.

The two field trials conducted by B&W PGG showed that while significant variation in oxidation air flow - from high flow to no flow - may allow for a decrease in measured slurry ORP of approximately 80 mV, changes in oxidation air flow alone are not sufficient to afford control of WFGD slurry ORP, and would likely have minimal effect during an ORP upswing event.

Consider development of a control scheme for the oxidation air flow vs. ORP levels as one trying to using a high power adjustment knob on a microscope while under coarse magnification; the controller would probably be constantly seeking.

Given a long enough time frame, a sulfite rich environment in the WFGD slurry may lower the ORP level, but this would only occur under steady state conditions. A sulfite-rich environment or a reducing environment may allow for the absorption and utilization of the increased oxidizers under controlled conditions. Since a commercial power plant is never under steady state conditions and the kinetically controlled reactions in the WFGD are in constant flux, running lean on oxidation air is not advisable or a preferred as a stand-alone method of control. The downside of running a lean oxidation air system, or not fully oxidized system, may be more detrimental to the operations of the WFGD system.

Disclaimer

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Dan Johnson is a Field Service Engineer with primary responsibility on WFGD applications. He has been at B&W for over 8 years with experience in construction, commissioning and tuning of environmental equipment. He has co-authored many papers and co-presented at several trade shows. Mr. Johnson has a BS in Mechanical Engineering from the University of Cincinnati and holds a PE from the State of Ohio.

"Fan Test" Helps Design Odor Control Facility

By Matt Fleming, Airflow Sciences Corporation

Sewer odor complaints are an increasing problem for large metropolitan areas. Sewer odor emissions are caused by the generation of positive air pressures within the sewer system and the resulting escape of odorous air through manholes and vents into the atmosphere. See Figure 15.

An increasingly popular odor control technique is to depressurize the sewer system by withdrawing air with a suitably sized and located fan. The withdrawn air is scrubbed to remove odors and then released into the atmosphere. The location and size of the fan(s) are critical to implementing a successful and cost effective odor control facility.

Airflow Sciences Corporation (ASC) recently conducted a fan test for the city of Vancouver, British Columbia. The City of Vancouver had received many odor complaints from the residents in a local neighborhood. Because the fan test was to be conducted in a residential neighborhood and immediately adjacent to a popular city park (Figure 16), the City of Vancouver was very concerned about odor and noise caused by the fan test.

ASC was able to address these concerns by providing a portable activated carbon scrubber and noise control barriers for the test (Figure 17). No noise or odor complaints were received during the week-long test. ASC also provided a 14,000 CFM fan, fan drive, and generator for the test. ASC was able to have equipment on-site on short notice from its home office in Detroit, Michigan, 2000 miles away.

In addition to the fan and its support equipment, ASC also supplied data loggers to monitor the sewer pressure at eight locations upstream and downstream of the fan location. By varying the fan flow rate, and by cycling the fan on and off,

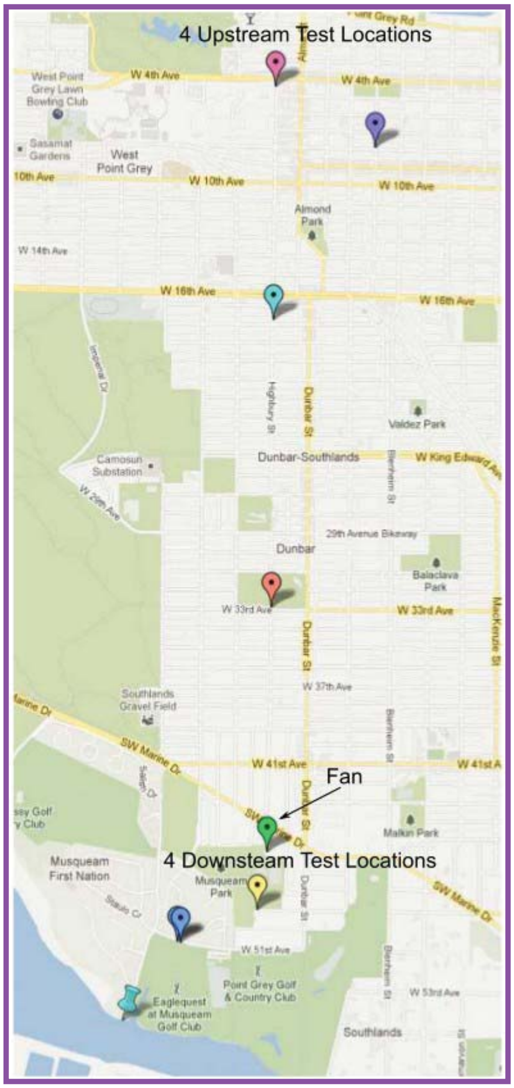

Figure 16: Vancouver, BC neighborhood map

Figure 15: Odorous fumes coming from manhole cover

Figure 17: Portable scrubber system

the pressure data showed the zone of influence of the fan at various extraction rates. This made it possible to determine the most cost-effective fan flow rate, size, and location.

Figure 18 illustrates the effect of the fan on the sewer pressure at select locations. The fan was cycled on and off so that its effect at different times of the day could be clearly seen. Various fan flow rates were tried in order to determine the flow rate required to keep the desired locations at negative pressure and avoid odor release to the community.

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Matthew F. Fleming, Field Testing Services Manager, has been with Airflow Sciences Corporation since May 1992. He has been involved in a wide diversity of projects including the development of a two phase flow computer model for the transport of pulverized coal in pipes; the design of a reduced drag, exterior automobile visor; and the development of a computer program for simulating the flow of coolant in turbine blades. In addition, he has designed and fabricated a vast assortment of field test equipment and completed numerous on-site test programs. Mr. Fleming received his B.S.E. in Aerospace Engineering from the University of Michigan in 1990, graduating Summa Cum Laude. He received his M.S.E. in Aerospace Engineering from the University of Michigan in 1992. Mr. Fleming has received certification as a Qualified Source Testing Individual (QSTI) to perform emissions testing per EPA standards. Mr. Fleming is also a named inventor on two US patents related to flow measurement.

Airflow Sciences
Corporation

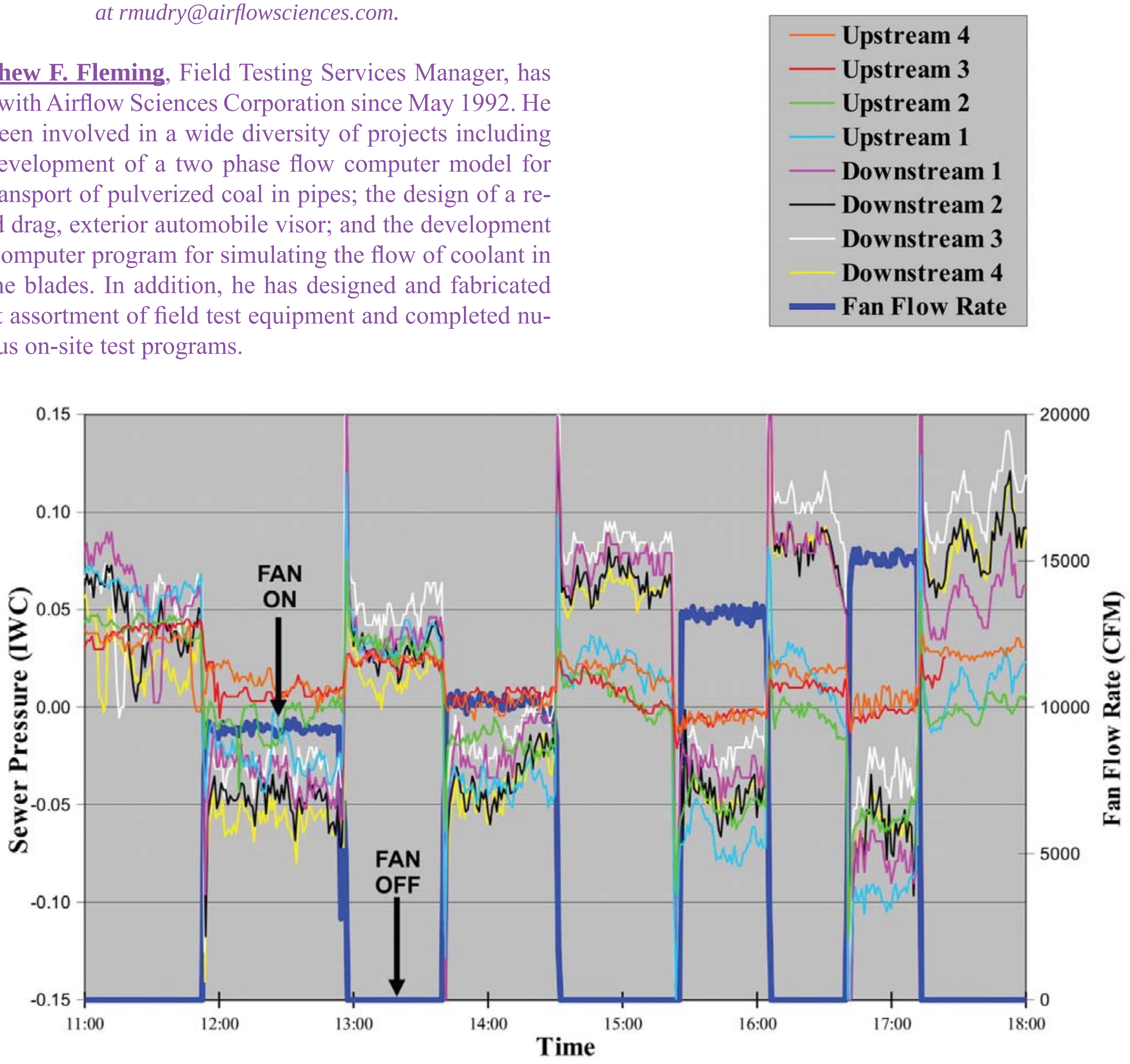

Figure 18: Sewer pressure monitor data

How to Kill Two Pollutants with One Sorbent: Combined Hg and SO_3 Removal using SBS Injection™

By Sterling M. Gray, Jim B. Jarvis, Steven W. Kosler, URS Corporation

Abstract

The U.S. EPA's Utility Mercury and Air Toxics Standards (MATS) regulation requires power plants to reduce emissions of hazardous air pollutants (HAPs) including mercury. Activated carbon injection (ACI) is the most widely used technology for the specific control of mercury emissions; however, ACI's effectiveness is greatly reduced in the presence of sulfur trioxide (SO_3).

This article describes a novel approach for mercury control that relies on the injection of a single sorbent to effectively remove SO_3 upstream of the air preheater (APH) which greatly enhances mercury adsorption onto the native "unburned carbon" in the flue gas downstream of the APH. Furthermore, removal of SO_3 prior to the APH allows for the flue gas temperature exiting the APH to be reduced, which further enhances mercury capture and improves the plant energy efficiency. The co-benefit capture of hydrochloric acid (HCl) and selenium from the flue gas using this approach is also discussed.

Background

Over the last decade many utilities have installed new emission controls on their coal-fired power plants, including selective catalyst reduction (SCR) systems for NOx control and flue gas desulfurization (FGD) systems for SO_2 control. One consequence of SCR retrofits has been a significant increase in the amount of SO_3 generated in the flue gas and the potential to create a visible sulfuric acid "blue" plume. In addition, higher SO_3 levels can adversely impact many aspects of plant operation and performance, including severe corrosion of back-end equipment, fouling of the APH, and limitations in the ability to operate at reduced loads due to SCR operating temperature constraints. The addition of SCR or FGD to a power plant, or a switch to higher sulfur fuels, can also trigger the U.S. EPA's New Source Review (NSR) rules. In some cases, power plants have been required to mitigate the elevated SO_3 emissions as a result of NSR rules.

The SBS Injection™ technology has been widely applied to control SO_3 emissions from coal-fired power plants. The technology injects a "sodium-based solution" into the flue gas, typically ahead of the APH or SCR. By removing SO_3 prior to these devices, many of the adverse impacts of SO_3 can be successfully mitigated, and plant performance and reliability can be improved. SO_3 removal efficiencies of greater than 98% have been achieved using SBS Injection, with stack emissions typically less than 1.0 ppm. The process has been installed on 24 boilers representing more than 15,000 MW of generating capacity, and has been in continuous operation for more than 10 years. A typical installation is shown in Figure 19.

Figure 19: SBS Injection system at Midwestern power plant

As with any emission control technology, proper design and operation is critical to ensure that desired performance and reliability is achieved. Because the SBS Injection technology relies on the injection of a wet sorbent solution into the flue gas, considerations must be made during design to ensure proper atomization and drying of the liquid to avoid solids deposition within the ductwork. In addition, the injection of any sodium-based sorbent can result in secondary reactions producing sodium bisulfate, which can lead to fouling of the APH. As a result, the injection location must be properly selected to provide adequate reaction time prior to the APH to ensure the SO_3 concentration is reduced sufficiently to avoid these reactions. Recent experience has shown that with proper design and operation of the SBS process, these operational issues can be easily overcome.

Mercury Control Challenges

The MATS regulation requires power plants to reduce emissions HAPs including mercury. ACI is the most widely used technology for the specific control of mercury emissions; however, the effectiveness of ACI is greatly reduced in the presence of SO_3. Plants burning medium- to high-sulfur fuels and equipped with SCRs, can have as much as 30-80 ppm of SO_3 in the flue gas. Research shows that even low levels of SO_3 (2-5 ppm) can inhibit good mercury adsorption. There has been significant effort to develop sulfur-tolerant carbons to overcome this challenge, but with only limited success. Dry sorbent injection (DSI) has also been used to control SO_3, but this technology is often unable to achieve the low SO_3 levels required for good mercury capture, and can adversely affect the performance of downstream particulate control equipment.

Another approach for mercury control that is widely used is catalytic oxidation and subsequent capture in a wet scrubber. SCR catalyst can be particularly effective for oxidation of mercury, but its performance is sensitive to flue gas temperature and halogen concentration. Wet scrubbers are very effective in capturing the oxidized form of mercury, but will not capture mercury in the elemental form. Sometimes, oxidized mercury captured in the scrubber can sometimes be converted back to the elemental form and be "re-emitted", thereby increasing stack emissions. Much research has been done to understand and control "re-emissions", with some success reported in recent years.

The U.S. EPA has also recently proposed new Effluent Limitation Guidelines (ELG) for the power industry. This new proposed rule places a limit of roughly 120 parts per trillion (ppt) for mercury in wet scrubber or FGD wastewater streams. For plants that discharge wastewater from their FGD system, this may present another challenge in managing the fate of mercury with their plant. Achieving the proposed limits may require additional physical and chemical treatment of the stream to transfer the soluble mercury from the liquid phase to the solid phase, with subsequent separation and removal from the waste stream. In the worst case, expensive mercury-specific treatment techniques may be required.

In addition to mercury, these two regulations place limits on acid gas (HCl, HF, etc) emissions in flue gas and selenium discharges in wastewater. The MATS rule requires HCl emissions to be limited to 0.002 lb/mmBtu as a surrogate for the control of emissions of acid gases. The proposed ELG rule could limit selenium levels in FGD wastewater streams to only 10 parts per billion (ppb). The ability to capture and remove these two species ahead of the wet scrubber could be advantageous and may be an effective strategy in complying with the regulations.

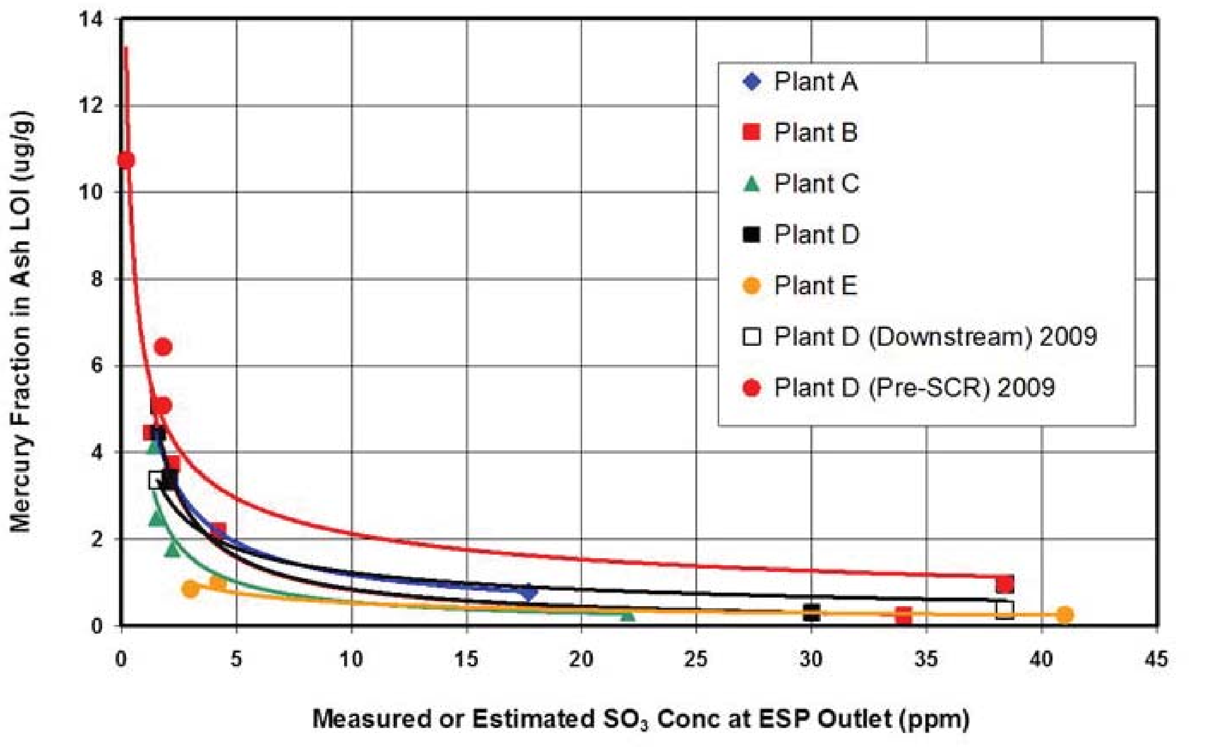

Figure 20: Native mercury capture rates greatly enhanced when SO_3 reduced.

A New Approach to Mercury Control

Given the challenges of controlling mercury emissions, and the associated high costs, there is a need for a new cost-effective approach that solves these issues. Over the last decade, testing by URS and others has confirmed the significant impact of SO_3 on mercury capture by activated carbon. URS has gathered extensive data from existing SBS Injection installations that also show how SO_3 impacts the "native" capture of mercury by the unburned carbon (UBC) or LOI that is typically present in flue gas. Figure 20 below shows how mercury adsorption onto unburned carbon increases dramatically as the flue gas SO_3 concentration is reduced from 5 ppm to 1 ppm. The data shown were collected by varying the SBS sorbent injection rate and then measuring both the mercury and LOI levels in the fly ash and the SO_3 concentration in the flue gas exiting the electrostatic precipitator (ESP). The results show that reducing the SO_3 down to very low levels can result in significantly higher mercury capture rates.

Industry research also shows that mercury adsorption onto carbon is temperature dependent with minimal capture above 350°F and maximum capture below 250°F. To investigate both the effect of flue gas temperature and SO_3 concentration, URS conducted a full-scale test program with co-funding provided by EPRI and the host utility. Testing was conducted at a Midwestern power plant with an existing SBS Injection system. The plant burns high-sulfur bituminous coal and is equipped with an SCR, ESP, and wet FGD.

During the test program, the APH exit gas temperature was varied from nominally 340°F down to 290°F at full load conditions by varying the degree of combustion air pre-heat. Temperatures as low as 265°F were achieved at reduced load conditions. The SBS sorbent injection rate was also varied from a typical molar injection ratio of 1.5 to an elevated ratio of 2.5 Na_2CO_3:SO_3. Flue gas measurements of elemental and oxidized mercury concentrations were made at the ESP outlet using a semi-continuous emission monitor (SCEM), and also validated with limited sorbent-trap testing in the stack. Flue gas SO_3 measurements were also made at the ESP outlet using the controlled condensation sampling (CCS) method. Coal and fly ash samples were collected during the test program and both analyzed for mercury and UBC content. Finally, HCl and selenium measurements were made in the coal, fly ash, and flue gas at the ESP outlet.

Parametric test results, summarized in Figure 21, show the overall mercury removal efficiency as measured from the coal to the ESP outlet. Results indicate that higher mercury removal was achieved by both increasing the SBS injection rate and lowering the flue gas temperature. At the highest temperature (340°F), mercury removal was limited to about 60% at elevated sorbent injection rates. However, at the lower flue gas temperature (270°F), mercury removal increased to 80% and above, even at the lowest sorbent injection rate. Test results also indicated that both elemental and oxidized mercury were removed across the ESP, ensuring a reduction in stack mercury emissions. For example, at the lowest flue gas temperature (270°F), the elemental mercury concentrations at the ESP outlet were reduced to about 0.6 lb/TBtu, well below the MATS emission limit of 1.2 lb/TBtu. During the testing, flue gas SO_3 levels at the ESP outlet ranged from 0.8 to 1.2 ppm, and fly ash LOI levels varied from 3.5 to 5.0%.

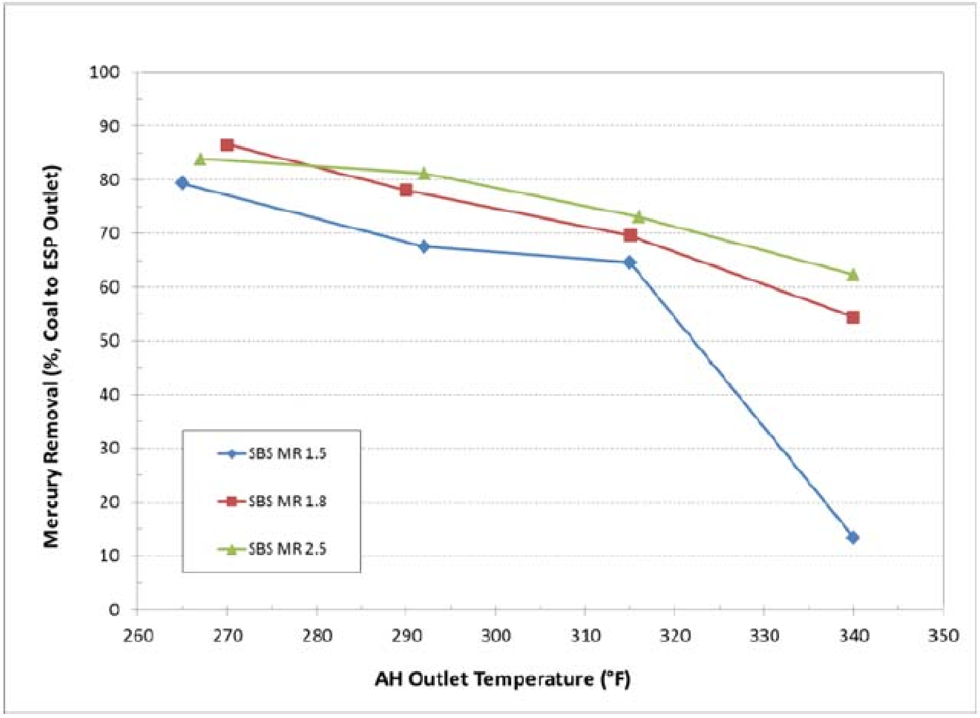

Figure 21: Mercury removal increases with lower flue gas temperature.

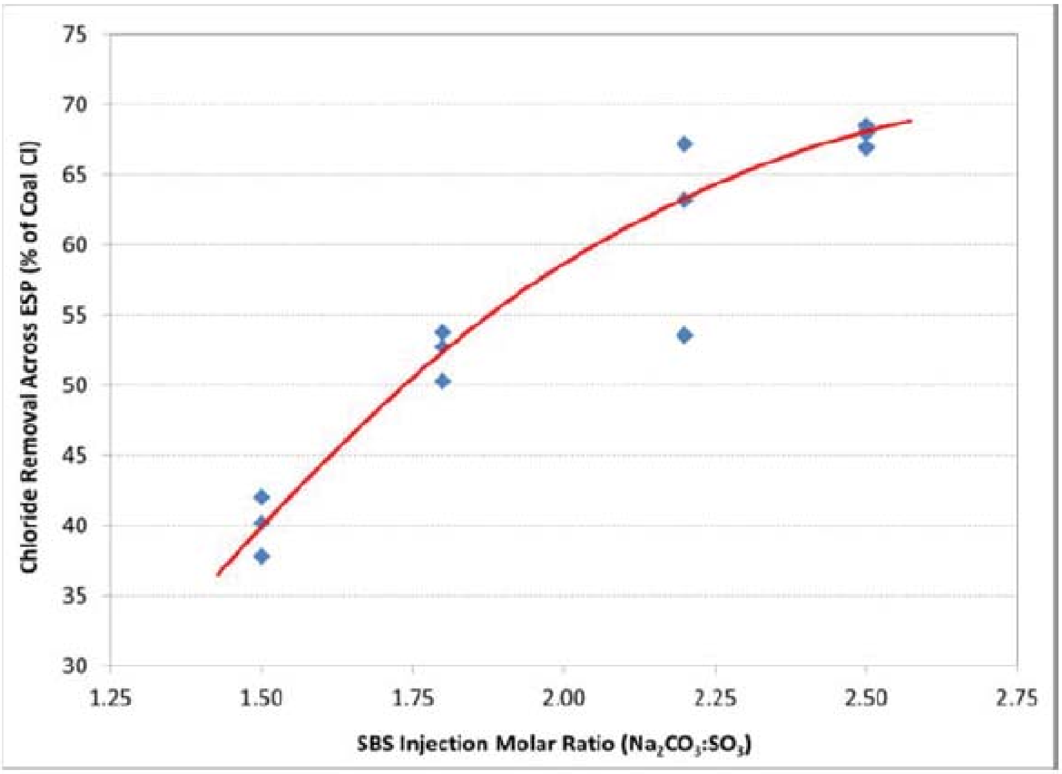

Figure 22: Results show significant co-removal of HCl using sorbent injection.

Results from the test program clearly show the benefit of both reducing the flue gas SO_3 concentrations to very low levels and reducing the flue gas temperature leaving the APH. By capturing a very significant fraction of the mercury across the ESP, the stack mercury emissions can typically be reduced to well below the MATS emission limit. Based on the positive results from the test program, the host utility has elected to upgrade their existing APH elements to achieve much lower flue gas temperatures and much higher mercury capture - a key component of their MATS compliance strategy.

The results described above demonstrate that it is possible to achieve very high removal of both SO_3 and mercury by injecting a single sorbent in the flue gas. Furthermore, by reducing the SO_3 concentration at the inlet to the APH to very low levels, it is also possible to eliminate fouling of the APH due to sulfuric acid and/or ammonium bisulfate (ABS). Based on research and testing conducted by a leading APH manufacturer, the APH can now be reliably operated at much lower temperatures, improving mercury capture and plant heat rate or energy efficiency. One might say that this new approach allows a power plant to "capture more mercury … by burning less coal".

Capturing more mercury in the fly ash also significantly reduces the amount of mercury that is captured by the wet scrubber, which can provide several potential benefits. First, if less mercury is retained in the scrubber, then the potential amount of mercury that can be "re-emitted" is also reduced, thereby lowering the risk that this phenomenon will result in exceedences of the MATS limit. Second, by lowering the mercury content in the FGD scrubbing liquor, it is much more likely that ELG limits for mercury content in FGD wastewater streams can be met without the need for additional treatment.

HCl and Selenium Co-Removal

As mentioned earlier, HCl emissions in flue gas and selenium discharges in wastewater are also regulated by the MATS and proposed ELG rules, respectively. Recent testing has shown that sorbent injection for the removal of SO_3 and mercury is also effective for the capture and removal of HCl and selenium from flue gas. HCl removal results as a function of the SBS sorbent injection rate are illustrated in Figure 22. At typical SBS sorbent injection rates, roughly 40% HCl capture was achieved, while elevated injection rates resulted in nearly 70% HCl capture. These results are consistent with previous testing that shows that SO_3 is preferentially removed, with excess sorbent available to remove HCl present in the flue gas. However, results at a given plant will vary depending on the relative concentrations of SO_3 and HCl in

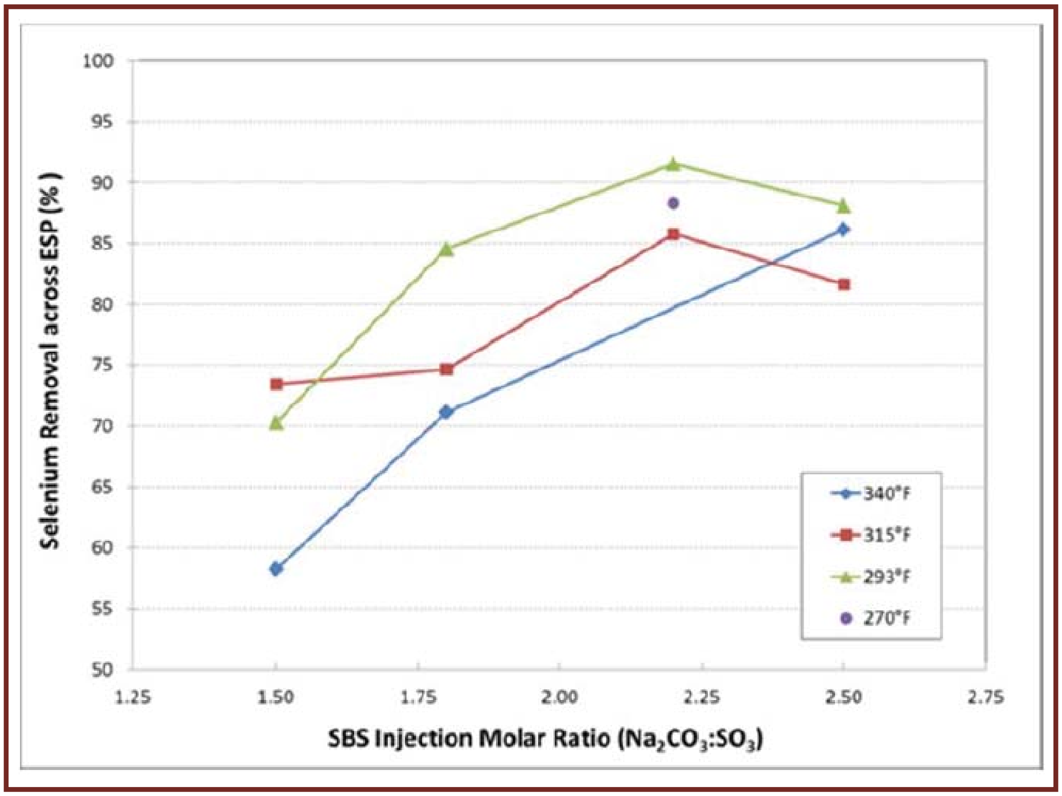

Figure 23: Results show significant co-removal of Selenium using sorbent injection

the flue gas, and the overall sorbent injection rate.

Co-removal of HCl with the fly ash can provide several advantages to the operating plant. Some plants must control the dissolved chloride levels in their wet scrubbers due to materials of construction and corresponding corrosion concerns. As a result, many plants must operate with a chloride purge stream from the FGD system. In most cases, this chloride purge stream must be treated prior to discharge. In addition, the newly proposed ELG rules may require additional treatment to meet new stringent limits for mercury and selenium. By capturing HCl in the fly ash, and reducing the amount captured in the FGD system, it may be possible to greatly reduce, or even eliminate, the need for a chloride purge stream. As a result, it may be possible to avoid the significant capital and operating costs associated with FGD wastewater treatment.

Effective capture of selenium has also been demonstrated using the SBS Injection process. Figure 23 shows selenium removal across the ESP as a function of the SBS sorbent injection rate and flue gas temperature at the APH outlet. Results indicate that 60-90% capture efficiency was achieved over the range of sorbent injection rates tested. As described earlier, the newly proposed ELG rules place stringent limits on selenium in FGD wastewater streams. By capturing a significant fraction of the gaseous selenium with the fly ash, it may be possible to meet the ELG limits without the need for costly treatment technologies.

Summary

New environmental regulations will require the removal of acid gases, mercury, and other air toxics from the exhaust gases and water discharges of coal-fired power plants.

Achieving these new stringent limits presents numerous challenges for conventional approaches that will require significant capital expenditures, as well as increased plant operating costs. However, recent testing has shown that the injection of a single sorbent can effectively remove the regulated pollutants, while also improving plant energy efficiency.

The SBS Injection process has been successfully applied to more than 20 boilers and 15,000 MW of generating capacity for the effective control of SO_3 emissions. Recent data show that significant co-removal of other regulated pollutants is also achieved. In fact, mercury capture rates of greater than 80% can be achieved using the “native” unburned carbon in the fly ash as a result of sorbent injection and a reduction in APH operating temperatures. This not only reduces stack mercury emissions, but also mitigates secondary mercury control issues such as FGD "re-emissions" and wastewater treatment. As a result, power plants may be able to comply with the MATS and ELG mercury emission and discharge limits without the need for costly mercury controls such as ACI, fabric filters, or wastewater treatment. This strategy also achieves an improvement in plant heat rate, thereby increasing plant energy efficiency and reducing plant operating costs.

Significant co-removal of HCl and selenium has also been demonstrated using the SBS Injection process. Capture of both species in the fly ash may be important for plants that currently operate with a wastewater stream to purge chlorides from the FGD system. For such plants, they may be able to eliminate this stream altogether or greatly reduce its flow rate and selenium concentration. As a result, it may be possible to avoid costly wastewater treatment requirements resulting from the proposed ELG rules.

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Sterling Gray is a Technology and Business Development Manager in the Process Technologies group at URS Corporation, located in Austin, Texas. In this role, he has been responsible for the development, commercialization, and optimization of the SBS Injection process for SO_3 removal in utility coal-fired power plant applications. Prior to this, Sterling spent the majority of his career in the field of air pollution control, focusing primarily on the research and development of SO_2 and NOx control technologies for the utility industry. Sterling has a bachelor's degree in Chemical Engineering from Michigan State University.

Integrating Flue Gas Conditioning for ESP's with MATS Control Strategies

By Richard Miller and Jean Bustard, ADA-ES, Inc.

Utilities will face many challenges to achieve full compliance with the newly imposed EPA Mercury and Air Toxics Standards (MATS) rules, depending upon current and anticipated fuel types and existing air pollution control systems. This could be especially difficult with older, marginally sized electrostatic precipitators that rely on trace levels of SO_3 in the flue gas to maintain optimum particle resistivity ranges.

Activated carbon injection is one of the leading technologies utilized for controlling mercury to required MATS levels. To date, greater than 288 systems have been installed or are under contract with another 247 systems out for bid. In the end, it is expected that over 55% of existing coal-fired power plants will have ACI installed for mercury control.

The negative impact of SO_3 on activated carbon and mercury control is well documented.[1] At concentrations above 10 ppmv, especially when flue gas temperatures are above 320°F, the interference from SO_3 can result in dramatically reduced mercury removals.[2] Achieving MATS levels for mercury reduction with ACI or unburned carbon in fly ash (typically measured as loss on ignition or LOI) typically require SO_3 levels to be maintained at less than 5 ppmv.

Additionally, to achieve required MATS levels for HCl reduction, the injection of high levels of hydrated lime is often required. Hydrated lime also captures SO_3, thus lowering SO_3 levels and, as a result, increasing the effective ash resistivity. Injection of hydrated lime for compliance must be balanced with maintaining adequate SO_3 to maintain resistivity and ESP performance. This can be difficult as coal and operating conditions vary.

Figure 24 shows predicted fly ash resistivity for an Eastern high sulfur coal with a highlighted region where resistivity could be problematic. When there is no SO_3, the resistivity is very high at a typical ESP operating temperature range of 300 to 350°F.

Another factor associated with dry sorbent injection and activated carbon is the overall increase in particulate loading to the ESP, typically fine powdered sorbent. Many

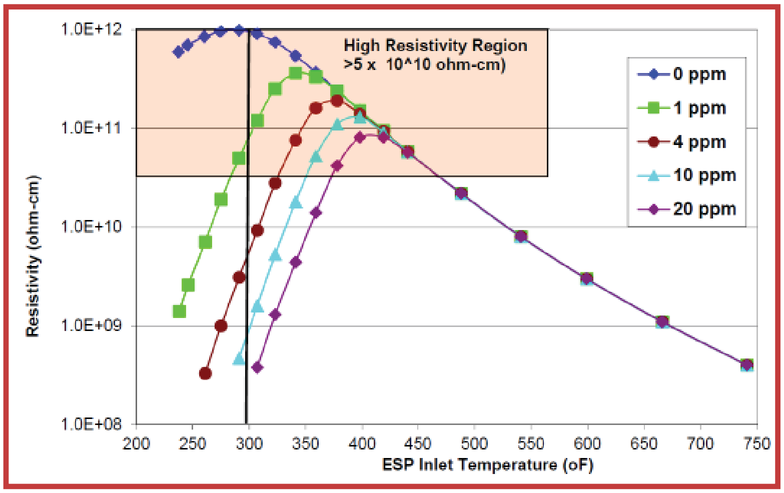

Figure 24: Predicted fly ash resistivity at various SO_3 concentrations

older or undersized ESPs were not designed to operate with this increased particulate loading.

As a result of a convergence of factors related to MATS compliance, there are added strains on ESP operation, even on units that traditionally have not experienced any ESP problems. Issues from use of sorbents such as hydrated lime have been demonstrated, such as reduced power levels, increased spark rates and loss of native SO_3 have been demonstrated. What was once an easy ESP application for use on higher sulfur, bituminous coal installations, may now become more difficult as the SO_3 levels are significantly reduced entering the ESPs due to hydrated lime injection.

ADA® RESPond™ Flue Gas Conditioning Technology, formerly known as ATI-2001, is non-SO_3-based and, as such, is compatible with sorbents for both mercury and acid gas control, meaning that it does not interfere with activated carbon or be absorbed by alkaline sorbents. This is especially important for those facilities that have existing SO_3 conditioning or traditionally have not required the use of external SO_3 conditioning due to the natural SO_3 levels produced from firing higher sulfur coals, but now may need hydrated lime based dry sorbent injection in order to achieve required MATS levels for HCl.

ADA has offered various ESP flue gas conditioning technologies commercially for over 15 years. These products are specifically designed to modify ash resistivity and help increase ESP power levels and reduce sparking rates, thereby maintaining and/or increasing ESP collection efficiency.
To date, numerous full-scale demonstrations utilizing these flue gas conditioning technologies have been conducted, in addition to commercial installations.

Case Study 1:

In this case, the host unit was an older B&W PC fired boiler brought into commercial service prior to 1970 with a rating of approximately 300 MW burning western sub-bituminous fuels. Two parallel gas ducts feed flue gas into a single, multi-chamber ESP casing. The ESP specific collection area (SCA) is 200 ft²/kacfm. At full load, the host unit produces approximately 1.1 MMacfm of flue gas at 290°F going into the ESPs.

Testing was conducted with the simultaneous application of dry sorbent injection and activated carbon injection. The purpose of the testing was to determine if RESPond would provide suitable conditioning of the fly ash to maintain the ESP's electrical performance while injecting Trona and sodium bicarbonate for SO_2 and SO_3 reduction and improve performance of activated carbon for mercury control.

During host unit baseline operation, high levels of SO_3 conditioning (>20 ppmv) were required to maintain ESP electrical performance. SO_3 conditioning was discontinued and the additive was applied. The flue gas technology successfully maintained power levels to those experienced with SO_3 conditioning and there was no change in opacity levels, which remained well below permit limitations.

The replacement of SO_3 flue gas conditioning with RESPond at this facility greatly improved performance of the activated carbon for mercury capture across the existing ESP. Over 90% mercury reduction was achieved at a greatly reduced rate of activated carbon injection. Figure 25 shows the performance of ADA's non-SO_3 flue gas technology in comparison to conventional SO_3 with injection of activated carbon for mercury control. This client added $CaBr_2$ to the coal for

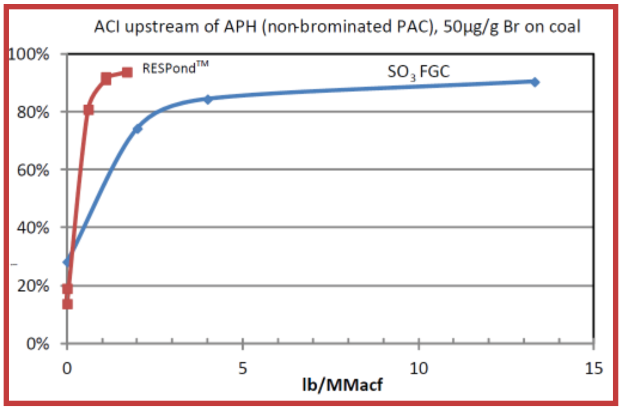

Figure 25: Impact of flue gas conditioning on mercury capture across the ESP casing

additional Hg oxidation. Results show that with RESPond, activated carbon usage was reduced by over 80%, thus preserving ash sales and reducing operating costs.

Case Study 2:

In this case, the host unit was a CE tangential fired boiler brought into commercial service in 1976 with a rating of approximately 350 MW burning western sub-bituminous fuels. ADA's flue gas technology was used to improve overall ESP performance at this facility.

- This unit did not previously have SO_3 conditioning, therefore when RESPond was injected, there was an immediate improvement in ESP total power and a concurrent drop in average spark rate.

- In this case there was a reduction in opacity from 17% to 8% within two hours of the start of injection.

Impact on secondary current, spark rates in the front fields are illustrated in Figure 26. As can be seen from this chart, ESP response in terms of increased power and reduced sparking was seen within 15 minutes of the start of injection. Complete conditioning of the ESP typically takes longer than this, since RESPond co-precipitates with fly ash and requires time to achieve full penetration to the precipitator outlet.

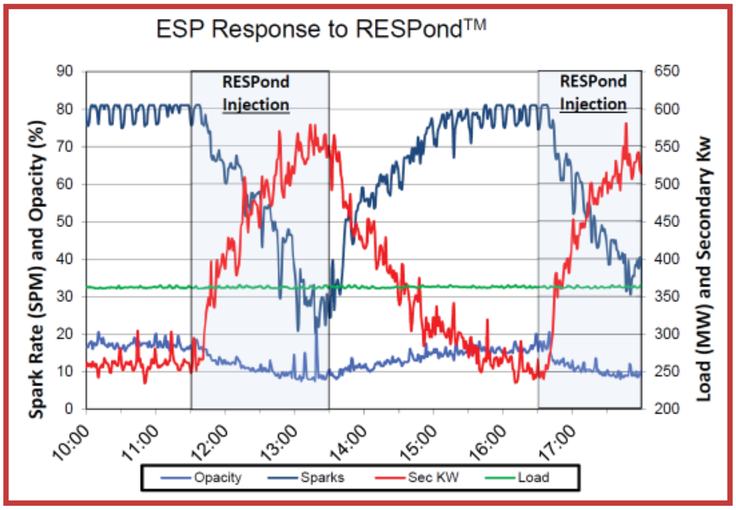

Figure 26: ESP response to RESPond^{TM} additive use

Case Study 3:

Laboratory resistivity with RESPond was evaluated for a client to determine the potential of the technology. Figure 29 presents the resistivity curves from these tests conducted on a western sub-bituminous coal fly ash. Two ascending temperature resistivity curves are shown; baseline ash with no conditioning and an ash sample treated with a typical level of ADA's flue gas conditioning agent. Laboratory testing demonstrated two orders of magnitude improvement from baseline resistivity levels in the ash.

Conclusion

ADA RESPond Flue Gas Conditioning Technology can be an effective addition to MATS compliance strategies for units with ESPs, activated carbon for mercury control and dry sorbents for acid gas control. ADA's flue gas conditioning technology does not interfere with the performance of activated carbon for mercury control, thus enabling optimum management of activated carbon usage and help preserve ash sales. RESPond can work in tandem with the injection of alkali sorbents to maintain ideal resistivity ranges even when SO_3 concentrations are significantly curtailed. RESPond may also provide significant benefits on higher sulfur coal units that now must inject high quantities of hydrated lime, required to achieve both mercury and HCl MATS emission levels. In its essence, RESPond works similar to conventional SO_3 conditioning by modifying ash resistivity resulting in improved power and reduced spark rates to maintain compliance opacity levels.

Figure 27: A typical FGC Injection skid

Figure 28: Typical FGC injection lance

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2. Curt Biehn and Greg Filippelli, "Dry Sorbent Injection for SO_3 and MATS", Reinhold APC Conference, July 2012.

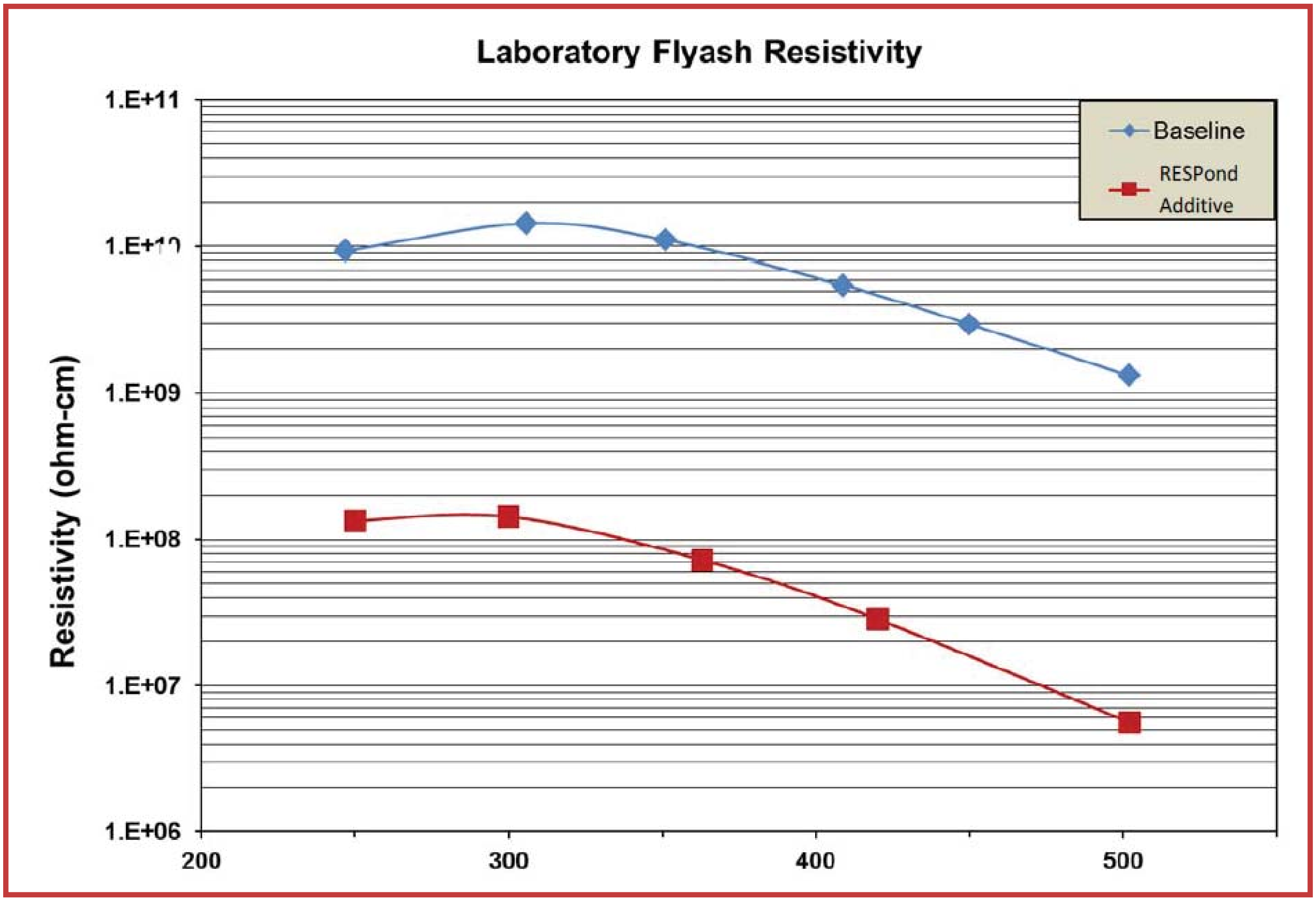

Figure 29: Example with a western subbituminous fly ash conditioned in a laboratory resistivity test cell with 10% moisture content using the IEEE 584 procedure.

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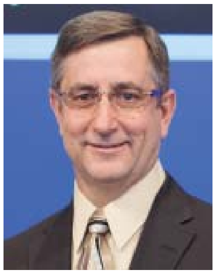

Richard Miller has over 37 with experience in mercury control, acid gas mitigation and fabric filter/ESP control systems technologies for the coal-fired boiler industry. Miller is the current Vice President of Business Development for ADA-ES, Inc.

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