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Executive Summary

Natural Gas Conversions of Existing Coal-Fired Boilers

By F.J. Binkiewicz Jr., R.J. Kleisley, McMahon, J.E. Monacelli, D.A. Roth, D.K. Wong, Babcock & Wilcox, Power Generation Group

This article will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision.
Full Story….

Real World Performance Results of Fabric Filters on Utility Coal Fired Boilers

By Tim Stark, GE Power and Water Air Filtration

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Full Story….

Dry Sorbent Injection Impacts on Hazardous Air Pollutant Metals

By Dr. Connie Senior, ADA-ES

In this article, the chemistry of DSI and of certain hazardous air pollutant (HAP) metals in coal combustion flue gas will be presented, followed by a discussion of the currents understanding of leaching from mixtures of alkaline sorbents and fly ash.
Full Story….

Comparison of Wet and Dry Electrostatic Precipitator (ESP) Technologies

By Aaron Benedict, James "Buzz" Reynolds, Sankar Seetharama, Siemens Energy Inc., Environmental Systems & Services

This article compares the two technologies and Siemens' experience with the technologies. To gain a better understanding of each technology a discussion of particle size is first required.
Full Story….

Can Dry Sorbent Injection Technology Really Work for HCl for MATS Compliance?

By Michael Thiel, Nol-Tec Systems

The focus of this article is HCl and SO_2. The specific limit for HCl is 0.0020 lbs/MMBtu. For SO_2, the limit is 0.20 lbs/MMBtu. Dry Sorbent Injection (DSI) has been proven to meet these standards in real world tests and permanent installations. Before we examine those test results, we'll discuss the basics of DSI. .
Full Story….

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Natural Gas Conversions of Existing Coal-Fired Boilers

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Abstract

Electric utilities are always searching for ways to minimize costs, improve availability and reduce emissions. Recent changes in the price of natural gas have made that fuel economically attractive, with the added benefit of reduced emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx) and carbon dioxide (CO_2). For those utilities with existing coal-fired units, conversion from coal firing to natural gas firing might be an option worth considering.

This article will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision.

Rationale for Considering Fuel Switching

The first step in the process is to identify the forces that drive the decision to convert from coal to gas. The key forces are regulatory (both in terms of emissions and as an offset for a new unit), fuel costs, the age of the plant and the need for plant output.

Regulatory forces are currently in a state of flux, with a wide range of proposed rules and legislative efforts that

Location	Ohio	Ohio	Oklahoma
Existing Unit Information			
-- Year built	1954	1956	1981
-- Original megawatts	152	103	390
-- Operating pressure (PSI)	2,050	1,480	2,640
-- Main steam temperature (F)	1,050	1,000	1,005
-- Reheat outlet temperature (F)	1,000	1,000	1,005
-- Original fuel	Pulverized bituminous coal	Pulverized coal	Pulverized coal
Target Performance Basis	100% NG with no pressure part changes	Minimize pressure part changes	Maintain 1005F w/excess air up to 87% MCR
Results and Limitations	Original maximum continuous rating; MCR (no limitations)	Maximum resulting SH temp = 950F; and Higher excess air for steam temperature control at lower loads	Cannot maintain steam temperature above 87% MCR without modifications; and Unable to fire 100% gas without pressure part modifications
Recommended Burner Modifications	Add gas elements	New low NO_X burners + OFA ports	New burners + NO_X ports
Recommended Pressure Part Modifications	Minimal to none required	Minimal to none required	Minimal to none required
Attemperator Recommendations	No changes required	No changes required	SH changes required
Fan Recommendations			
-- Forced draft	Appears OK, evaluation by others	No changes required	Static capacity deficient
-- Induced draft	Appears OK, evaluation by others	No changes required	No changes required
-- Gas recirculation	Replace FGR fan and drive	No recommendations made	Removed from service
Air Heater Recommendations	No changes required	No changes required	Design static pressure deficient

Figure 1: Comparison Table - Study results of Typical Pulversized Coal to Natural Gas Conversion

could have a far-reaching impact on coal-fired operation. What appears likely is that some form of CO_2 controls will be enacted in the near future. Those controls could be part of a cap-and-trade system (similar to previous allowance programs for SO_2 and NO_x) or they might take the form of gradual reductions to meet increasingly stricter goals. Regardless of the final form, the industry is reasonably certain that there will be some additional controls placed on power plant owners. Utilities must also factor in the future need for electrical power generation – either because of market demand projections or to replace a unit that might be approaching the limit of its useful service. There also may be regulatory issues to evaluate, such as New Source Review and offsets for other emissions regulated by state and federal laws.

The price of natural gas has recently become more attractive as a baseload fuel due to additional supply and reduced demand from general industry. There are many different projections of where gas prices might be in the near future, all of which are based on the forces of supply and demand. The current price of natural gas is relatively low and stable compared to previous years. Utilities should be aware that natural gas prices are much more sensitive than coal prices to short term changes in supply and demand. While current economic conditions favor natural gas usage, Babcock & Wilcox Power Generation Group, Inc. (B&W PGG) strongly advises its customers to evaluate potential price volatility as a key component in the decision making process.

A plant may be considered for fuel switching based on its age and how close it would be to a possible retirement or major rebuild. The timing for fuel switching may be ideal if the boiler in question is already under consideration for major projects like superheater replacement, burner modifications, air system changes and/or the addition of back-end emissions control equipment. Consultants can assist in comparing the costs and benefits of different scenarios to help make the best decision based on the specific needs of the plant.

One of the other key factors to consider is the need for plant output, including a potential for de-rate and/or increased turn-down capability. A unit's continued usefulness might involve its ability to operate or be on standby during periods of low load.

As utilities look at their long-term forecasts, plants that operate efficiently and with high availability will play a key role in meeting future demand. As such, these plants will need to be evaluated for projects that will extend their useful life. Those projects might be targeted for efficiency improvements with coal as a fuel (burner upgrades, emissions control equipment, etc.) or as fuel-switch projects that take advantage of the benefits of natural gas.

Options

An engineering study can be performed to help determine the best options for your specific application. Among the many options to consider are:

1. Fuel switch with modifications to the existing boiler
2. Fuel switch for the existing boiler and the addition of a gas turbine to the existing boiler cycle
    - addition of simple cycle to the existing system
    - hot windbox repowering
    - combined cycle repowering
3. New combined cycle plant (elemental review) with retirement of the existing coal plant

Each option has advantages and disadvantages, including cost and operational considerations, including:

- comparison of modification costs vs. capital cost of a new gas turbine
- impact of future changes in fuel prices and the potential risk associated with natural gas price volatility
- life expectancy of gas turbines and heat recovery
- steam generators (HRSG) compared to steam boilers
- amount of acceptable de-rate

Since no two plants are identical, it is important that utilities work with an experienced supplier to evaluate the best solutions for their needs.

1. Fuel Switch with Modifications to the Existing Boiler

The most obvious change to a power plant that switches from coal to gas will be the modifications to the fuel handling, storage and distribution equipment. The plant must receive natural gas via a pipeline spur from the local main transmission line. If a spur does not currently exist, the plant will need to evaluate the costs and activities (permits, land rights, etc.) associated with constructing a new spur. Once inside the plant perimeter, the gas must be metered and piped to the boilers, where new gas burners will be required (or to a new gas turbine if applicable).

If the existing boiler is modified for gas-firing, the convection pass, ducting and windbox will likely need modifications. The extent of the modifications will be determined by an engineering study that will look at overall furnace absorption, furnace exit gas temperature, and tube bank arrangement/material changes (superheater, reheater and economizer). Other operational changes like sootblowing schedules, attemperator spray flows, air heater operation and operation of any back-end emissions control equipment will need to be adjusted for the switch from coal to gas.

Technical Considerations

As the engineers study your plant, they will evaluate the impact of the following technical considerations:

- characteristics of natural gas vs. original or current fuel
- impact on boiler design and capacity
- impact on cycle efficiency
- boiler and environmental equipment modifications
- burner modifications
- convection pass modifications
- changes to fans, ductwork, fluework, etc.
- amount of acceptable de-rate

Financial Considerations

Any modification to an existing plant carries considerable cost implications. This is true when upgrading a coal plant with new components for higher efficiency and/or lower emissions. Likewise, there are financial considerations for switching fuel from coal to natural gas. Cost ranges for modifications for the units shown in the comparison table on page 1 are estimated to be in the range of $50 to $75/kW.

The unique conditions of each plant will necessitate a detailed study of the potential operational options and their corresponding costs. These costs include only modifications to the boiler island. Excluded are costs related to bringing natural gas supply to the boiler.

2. Fuel Switch for the Existing Boiler with Addition of a Gas Turbine

Technical Considerations

The concept of repowering existing power plants is currently viewed as an option to economically meet new demands for improved efficiency, power growth and stricter environmental regulations. Partial repowering is the conversion of an existing site to combined cycle where the boiler and steam cycle are retained to the greatest extent possible. There are several major partial repowering alternatives. Many of these alternatives have multiple possible equipment configurations that can be considered depending on the option. Low gas turbine exhaust oxygen concentrations (as low as 12%), and high exhaust temperatures (exceeding 1100F) can provide design challenges depending on the combustion turbine used for this configuration.

2a. Addition of Simple Cycle to the Existing System

This technology uses the existing boiler and steam turbine equipment in essentially its original configuration. In this design, a gas turbine and feedwater heater are added in parallel to the existing boiler. Figure 2 provides a bullet summary and illustrates a typical equipment arrangement for this option. Depending on the specific plant configuration, balance-of-plant (BOP) material and erection services are required to complete this retrofit.

2b. Hot Windbox Repowering

In this configuration, a gas turbine is added to an existing plant and the exhaust from the turbine is ducted directly to the boiler windbox where it is used as combustion air for the boiler. The existing air heaters are typically retired with new stack gas coolers (or partial HRSG) added in parallel to the feedwater heaters to maximize cycle efficiency. Figure 3 (see on page 4) provides a bullet summary and illustrates a typical equipment configuration for this technology.

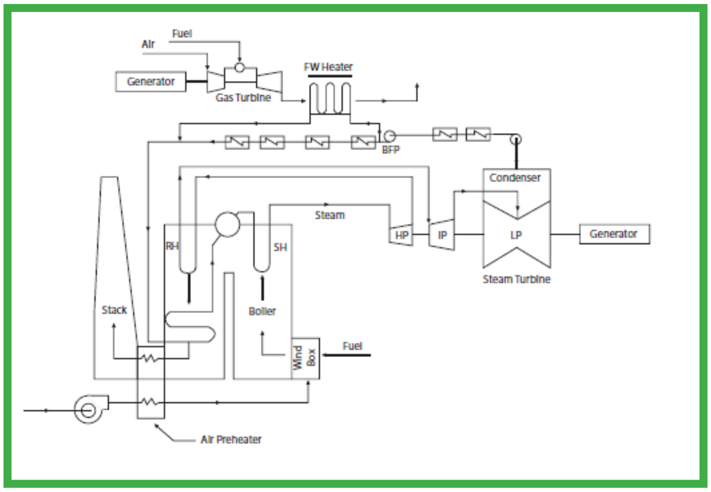

Figure 2: Addition of simple cycle

- *New gas turbine*
- *New recuperative feedwater heater(s)*
- *Retains steam system*
  - *closes some extractions and feedwater heaters*
- *Advantages*
  - *low additional capital cost*
- *Disadvantages*
  - *small efficiency gain - 2% to 3%*

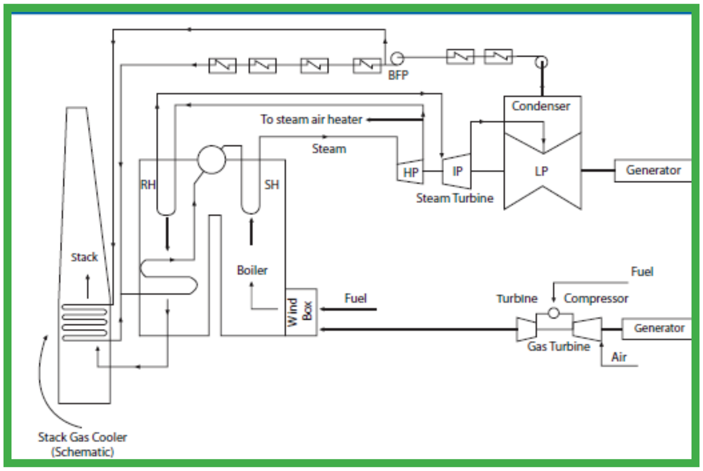

Figure 3: Hot Windbox Repowering

- *New gas turbine*
- *Retains boiler, steam turbine, generator, etc.*
- *Advantages:*
  - *moderate power increase of up to 50%*
  - *efficiency improvement of up to 15%*
  - *retains current equipment and if desired, current fuel*
  - *reduced emissions*
- *Disadvantages*
  - *requires new high temperature combustion air system*
  - *may require boiler surface changes and/or de-rate*
  - *requires special high temperature and low O_2 burners*

Depending on the specific plant configuration, significant boiler and BOP material and erection services are required to complete these retrofits. This has been the repowering configuration of choice outside of the U.S. with Holland having more than 12 plants designed in this configuration (both retrofit and original). B&W PGG designed two new plants based on this cycle configuration in the early 1960s. Recent improvements in gas turbine technology have made integration of these machines with boilers more challenging than in the past.

2c. Combined Cycle Repowering

In this configuration, a gas turbine is added to an existing plant and the exhaust from the turbine is ducted to the boiler windbox where it is used as combustion air for the boiler. This configuration uses a supplemental heat exchanger (or partial HRSG) or mixes ambient air upstream of the boiler to cool the exhaust temperature to levels acceptable to existing windbox materials. The existing air heaters are typically retired with new stack gas coolers (or partial HRSG) added in parallel to the feedwater heaters to maximize cycle efficiency.

Figure 4 provides a bullet summary and illustrates a typical equipment configuration for this technology. Depending on the specific plant configuration, significant boiler and BOP material and erection services are required to complete this retrofit.

Financial Considerations

As the repowering configuration can vary significantly depending on the goals and constraints of a given system, cost for such a conversion can span a broad range. The combustion turbine will likely be the largest single component and cost. Estimates on retrofit costs range from $180 to $1,025 per unit kW increase in power.

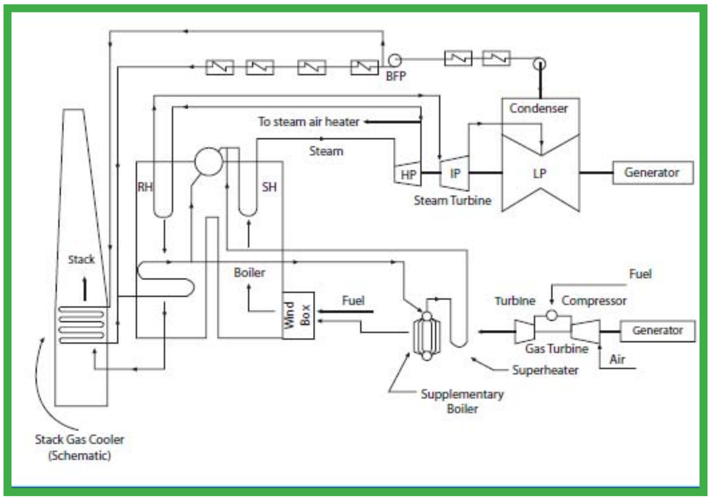

Figure 4: Combined Cycle Repowering

- *New gas turbines(s) and supplemental HRSGs or stack gas cooler*
- *Retains boiler, steam turbine, generator, etc.*
- *Advantages:*
  - *moderate power increase of up to 70%*
  - *efficiency improvement of up to 15%*
  - *retains current equipment and if desired, current fuel*
  - *reduced emissions*
- *Disadvantages*
  - *requires more complex steam system interface and piping systems*
  - *may require boiler surface changes and/or de-rate*
  - *requires special low O_2 burners*

3. New Combined Cycle Plant with Retirement of the Existing Coal Plant

A modern, highly efficient combined cycle plant is always a consideration when evaluating a fuel switch from coal to gas, especially when a considerable increase in power generation is needed. The higher capital cost of this option requires a careful analysis of its suitability to the unique needs of each utility.

This report is not intended to review every factor related to switching from coal to natural gas, but it is important for each prospective utility to consider the hidden costs associated with the retirement of a coal plant, including the cost of decommissioning or mothballing, as well as any site remediation costs. It is only when all the true costs are identified that the real savings from a fuel switch can be fully and properly evaluated.

For further information contact Don Ryan at deryan@babcock.com

Don Ryan

is the Manager of Advanced Technology Development for the B&W Power Generation Group in Barberton, OH. He graduated from Clarkson University in 1974 and started with Babcock & Wilcox as a utility boiler performance engineer. Since then he has held a variety of engineering and supervisory positions within B&W gaining experience on a wide variety of B&W products ranging from NG fired Package boilers to PC fired Supercritical units. Don is a Registered PE in Ohio and received an MBA from the University of Akron in 1985.

Don Ryan of B&Wgave one of the boiler presentations at the WPCA Coal to Gas Conversion Seminar at Gulf Power and Michigan.

A technical panel at the same seminar discussing the aspects of Coal to Gas Conversions.

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Real World Performance Results of Fabric Filters on Utility Coal Fired Boilers

By: Tim Stark, GE Power and Water Air Filtration

Abstract

This article examines how fabric filters behave in real-world environments, taking into account differential pressure changes, emissions levels and scrubbing results. It will address the effects that fabric finish and pressure drop have on scrubbing results and will show that the key to obtaining the scrubbing performance out of the dust-cake on the filter bag is the maintenance of that dust-cake by controlling pressure drop across the baghouse. In addition, this article will identify the effects that the other gas stream treatment equipment in line with the baghouse have on the dust-cake, and the system's ability to manage the pressure drop. The baghouses used in these case histories include both pulse-jet and reverse-air-style cleaning methods.

Introduction to Fabric Filters

Fabric filters, or baghouses, have been used to capture particulate from combustion processes for more than 50 years. They grew popular in the power generation industry in the 1970s after the first installation of a reverse-air-style fabric filter. Pulse-jet, another type of fabric filter, was also implemented on coal-fired power generation applications in the early 1970s, with the first actual utility installation taking place in the early 1990s.

Reverse-Air Style Fabric Filter

Reverse-air was the original style of choice for dust collection in utility applications. In the 1970s, this style of collector was more suited for utility applications than pulse-jet because of the proven relatively low air-to-cloth/offline cleaning technology.

Reverse-Air Technology

- Air-to-cloth ratio target: 2.5:1 or lower
- Large footprint
- Offline cleaning
- Woven fiberglass fabric
- Finish options: Teflon™ B, acid resistant, expanded polytetrafluoroethylene (ePTFE) membrane
- Dust collected on inside of filter-no support cage utilized
- Average bag life range: 5-10 years

Pulse-Jet-Style Fabric Filter

The pulse-jet-style fabric filter, while in service since the early 1970s on coal-fired applications, was not yet cost-effective enough and did not have the performance track record nor the technology advancements required to operate at the scale of a large utility boiler application. As technology advanced and performance objectives were proven on smaller-scale industrial boiler applications, the pulse-jet technology gradually became the choice on utility installations.

Pulse Jet Technology

- Air-to-cloth ratio target: 3.5:1 or lower
- Smaller footprint
- Online cleaning with ability for offline cleaning
- Fabric options: woven fiberglass, polyphenylene sulfide (PPS) felt, acrylic felt, P84™ felt, aramid felt, fiber blends
- Finish options: acid resistant, singe, Teflon coatings, micro-denier, ePTFE membrane
- Dust collected on outside of filter
- Support cage utilized
- Average bag life range: 3-6 years

Lab vs. Real-World Conditions

While a fabric filter serves to remove particulate from the gas stream prior to the stack, it must do so while also controlling the fabric filter pressure drop so that there is proper ventilation during combustion and the cost of maintenance and fan energy consumption are minimized. This is a relatively simple task under conditions typically found in the lab.

Lab conditions

- Constant temperature
- Constant volume
- Constant moisture level
- Constant gas stream chemistry
- Constant grain loading

Using the above criteria for a gas stream in the laboratory yields acceptable performance results for most fabric and finish options. The real world has more challenging criteria for a fabric filter.

Real-world conditions

- Temperature: ranges from ambient to over 400 degrees Fahrenheit, depending on the scrubbing technology before the fabric filter
- Volume: dependent on load and temperature
- Moisture level: dew point excursions, tube leaks, fire suppression system upsets, door seal leakage, scrubber system upsets
- Gas stream chemistry: fuel changes, scrubber system upsets, ammonia levels when SCR technology is used, carbon present when activated carbon injection is used
- Grain loading: uneven gas stream distribution, material handling system upsets, fuel changes, offline cleaning

It is most important for the fabric filter to maintain pressure drop in an acceptable range, while also meeting emissions requirements, under all of the typical operating conditions that occur. Meeting these goals and doing it cost effectively boils down to dust-cake management.

Dust-Cake/Emissions Management

Over time, a dust-cake develops on the surface of the filtration media as a result of the particulate in the gas stream. In a coal-fired boiler, for example, this dust would consist of fly ash and any materials used to treat the gas stream (lime, trona, powder-activated carbon, etc.) before it collects on the fabric filter. This dust-cake is controlled by the baghouse cleaning system. The dust-cake performs two critical functions in the baghouse:

1. Filtration efficiency: The fabric filter acts as a support structure for a dust-cake that actually creates and controls efficiency. The fabric itself is not as efficient as the dust cake that is created on its surface, and the fabric alone cannot allow the system to meet environmental regulations. This dust-cake also provides some protection against the incoming gas stream, keeping the fabric from being directly subjected to the incoming dust load.

2. Gas-stream contact with dust-cake: In a coal-fired boiler that uses scrubber technology or activated-carbon injection technology before the baghouse, the dust-cake on the filter is providing some of the contact time between the gas stream and the materials injected into the gas stream for pollution control.

The key to controlling this dust-cake is monitoring the pressure drop and controlling the cleaning to maintain the dust-cake.

Over-cleaning filter bags is one of the main causes of premature bag failure. First of all, the filter has the ability to withstand a certain number of cleaning cycles over the course of its life. If we clean a filter every five minutes, it may last two years. If we clean it every 10 minutes, it may last four years. The cleaning energy will slowly degrade the filter much like cleaning fabric in a washing machine will degrade clothing over time. The less we clean, the longer the fabric should last. The other problem with over-cleaning is it does not allow a dust-cake to properly develop, leading to either dust penetrating into the depth of the fabric and becoming permanently lodged there (blinding) or the dust passing completely through the fabric and ending up as emissions (bleed-through). Most people intuitively believe that the more they clean the filters, the lower the pressure drop and the lower the potential for emissions, but the opposite is true: it is the dust-cake that provides the efficiency and protects the fabric from premature blinding and/or bleed-through.

In a *utility* baghouse, with gas stream treatment equipment upstream of the baghouse, the dust-cake has another purpose: create more contact time between the gas stream and the dust to help scrub the gas stream. This is an important variable to note. When trying to improve the filter's ability to release dust-cake, we often consider other fabric finishes. This raises the question about degrading the scrubbing results with filters that can potentially operate at a lower overall pressure drop. Can we improve dust-cake release to the point where it adversely affects the scrubbing characteristics of the dust-cake? Real-world results show that the fabric finish does not necessarily affect the filter's ability to create the dust-cake needed to accomplish scrubbing goals. Dust-cake management, regardless of the fabric finish used, continues to be the important factor when operating a power plant baghouse.

Potential Effects on Dust-Cake Management of Gas Stream Treatment

The air pollution control equipment used in today's coal-fired utility plants will almost always consist of more than just a fabric filter. Various different gas stream treatment technologies are used either before or after the fabric filter to treat the gas stream before it leaves the stack. Not only does

	Acrylic	PPS	Aramid	Fiberglass	P84	Pleated elements
Max Operating Temp	265 F 130 C	375 F 190 C	400 F 204 C	500 F 260 C	500 F 260 C	Dependent on base fabric
Concerns in coal fired boiler applications	Lowest maximum operating temperature.	Susceptible to degradation at elevated temperatures coupled with oxygen levels over 12%.	Not as capable as PPS in chemically active gas stream environment.	Woven style fabric that is more fragile than other options. Requires tight tolerance to be maintained on bag-to-cage fit in pulse jet applications.	Dimensional stability at higher temps over 400 F. Requires oversizing of filter to maintain proper bag-to-cage fit.	Air to cloth ratio must be below 3.5 to 1. Applicable only when additional cloth area is needed to lower air to cloth ratio and eliminate inlet abrasion.
Relative Cost	$	$$$	$$$	$$	$$$$	$$$$$
Fabric treatments to improve performance	**ePTFE Membrane**: Laminated to collection surface-most efficient option, enables fabric to handle system upsets reviewed in paper at more consistent airflow/less cleaning frequency. **Micro-denier fibers/Tri-lobal fibers**: Creates improved efficiency over standard fibers by increasing total fiber surface area. Limited improvement over ability to handle upset conditions reviewed. **PTFE Coating**: Non-membrane surface coating used to improve dust cake release-sacrifices ability to maintain consistent airflow leading to increased cleaning frequency/high differential pressure. **Singe:** Removes some of the fabric surface area, creating an improved ability of the fabric to release dust cake. Limited improvement over ability to handle upset conditions reviewed.					

Figure 5: Standard Fabrics Used in Utility Coal Fired Applications

this equipment have the potential to affect the performance of the fabric filter, the fabric filter can also affect this equipment.

To maintain a lower pressure drop for a longer period of time with the lowest cleaning frequency possible, end users have chosen different fabric types and fabric finishes. The gas stream treatment equipment used in conjunction with fabric filters can create conditions that make it more challenging for the cleaning system to maintain pressure drop. There are several instances where the fabric style or finish has been successfully changed in order to improve a system's ability to maintain pressure drop in the correct range with the lowest cleaning frequency possible.

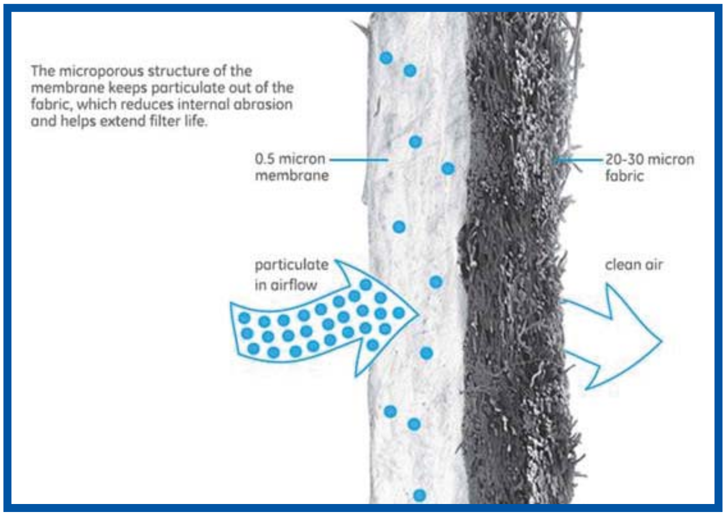


Figure 6: The microporous structure of the membrane

The most successful example in recent years has been the treatment of the base fabric with an expanded polytetrafluoroethylene (ePTFE) membrane. In brief, the membrane creates a very slick and highly efficient surface that allows the dust-cake to be maintained with less cleaning energy. This helps the system not only handle a sticky, difficult-to-clean dust-cake, it decreases cleaning frequency (leading to longer filter life). The gas stream treatment options listed below all have an effect on the dust-cake that the fabric filter handles.

While ePTFE filters enable the fabric filter to run at a lower pressure drop regardless of the changes in gas stream, the real-world results show that they do not adversely affect the scrubbing results from the potential decrease in contact between the gas stream and the dust-cake.

Scrubbers

Scrubbers are used for flue gas desulfurization (FGD) and acid gas control. There are several different technologies used.

- Spray dry FGD-typically upstream of the fabric filter
- Wet dry FGD-typically downstream of the fabric filter
- Circulating dry scrubber
- Dry sorbent injection

Potential fabric filter effects:

- Increase in grain loading
- Potential for moisture introduction into fly ash, leading to high pressure-drop/increased cleaning requirements
- Potential for decreased inlet temperature, increasing the risk of the gas stream dropping below the acid dew point before or inside of the fabric filter
- When scrubber is downstream of fabric filter, inefficient operation can lead to increased cleaning requirements for downstream technology

Selective Catalytic Reduction (SCR)

SCRs are used to convert nitrogen oxides (NOx) with the aid of a catalyst into diatomic nitrogen (N_2) and water. Typically ammonia is added into the flue gas stream and is absorbed onto a catalyst.

Potential fabric-filter effects: Sticky dust created by ammonium bisulfate that leads to higher pressure-drop/increased cleaning frequency

Electrostatic Precipitators (ESPs)

ESPs remove particulate from the flue gas by using electrical forces. The dirty gas stream is passed through an electrical field set up between electrodes of opposite polarity. In the utility industry, where ESPs were originally installed as the primary Air Pollution Control device, they sometimes are left in service after the addition of a fabric filter downstream from the ESP.

Potential fabric filter effects:

- Lower grain loading -- a good thing -- leads to potentially lower cleaning frequency
- Potential for applying fabric filter at a higher A/C ratio based on lower grain loading
- Can change the particle size distribution going to the fabric filter, removing the larger particulate

and allowing mostly the finer particulate to pass through. This can create a more challenging dust-cake for the baghouse

Carbon Injection

One method to help control mercury emissions is the injection of activated carbon into the flue gas to adsorb mercury before it exits the stack. This is typically done upstream of the fabric filter.

Potential fabric filter effects:

- Increased grain loading
- Fire potential
- Inability to sell fly ash from baghouse

Real-World Upset Conditions Affecting Fabric Filters

The fabric filter has several jobs to perform in a coal-fired boiler application. It needs to maintain pressure drop while meeting all environmental regulations in conjunction with the other pieces of environmental equipment in the system. On top of that, upset conditions in the real world can present challenges to the fabric filter. If the fabric filter can't handle the upsets, the result could lead to the plant not being able to run at the required load demand or being forced to shut down because of an inability to meet environmental regulations. The other issue is if the upset conditions require continuous cleaning for prolonged periods of time, leading to premature bag failures and shorter bag life than the budget anticipates.

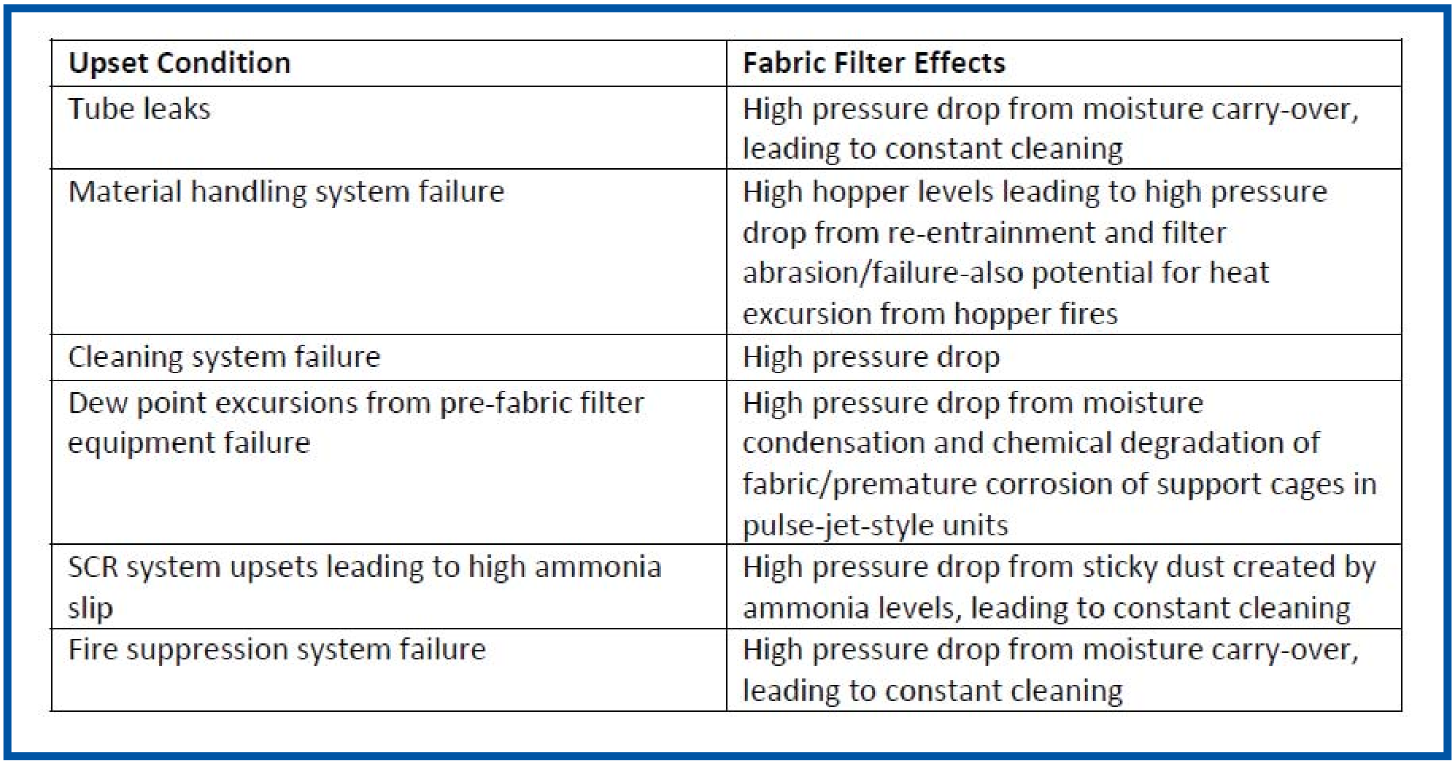
Conclusions

Fabric filters utilized on coal-fired boilers face real-world environments that make their primary goals of managing pressure-drop, efficiency and a percentage of the systems scrubbing performance a challenge. Dust-cake management is critical in ensuring these goals are met. Multiple factors can have an impact on a system's dust-cake:

- Low inlet temperatures
- High moisture levels
- Challenging dust-cake created when using scrubbers/SCRs/activated carbon injection
- Longer-than-normal filter bags requiring aggressive cleaning to maintain pressure drop

Managing the dust cake requires controlling the filter differential pressure and is critical in ensuring:

- Required particulate removal efficiency
- Plant load requirements
- Necessary scrubbing by dust-cake on filter media
- Minimized energy cost for operating fabric filter
- Maximized filter life with minimized maintenance costs



Upset Condition	Fabric Filter Effects
Tube leaks	High pressure drop from moisture carry-over, leading to constant cleaning
Material handling system failure	High hopper levels leading to high pressure drop from re-entrainment and filter abrasion/failure-also potential for heat excursion from hopper fires
Cleaning system failure	High pressure drop
Dew point excursions from pre-fabric filter equipment failure	High pressure drop from moisture condensation and chemical degradation of fabric/premature corrosion of support cages in pulse-jet-style units
SCR system upsets leading to high ammonia slip	High pressure drop from sticky dust created by ammonia levels, leading to constant cleaning
Fire suppression system failure	High pressure drop from moisture carry-over, leading to constant cleaning

Figure 7: Common Upsets Causing Fabric Filter Issues

Filter media technology exists that improves the ability of the fabric filter to operate under real-world conditions. The use of ePTFE membrane laminated filters improves the performance of the fabric filter by allowing it to operate at a lower pressure drop and recover from common upset conditions. This style of filter shows no change in the scrubbing performed by the dust-cake and no in increase in the use of adsorbents as long as pressure drop is managed.

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Dry Sorbent Injection Impacts on Hazardous Air Pollutant Metals

By Dr. Connie Senior, ADA-ES

Dry sorbent injection (DSI) is intended to remove acid gases from the flue gas via the injection of sorbents. However, there are other chemical reactions that happen in the flue gas and in the fly ash-sorbent mixture that should be considered when contemplating using dry sorbent injection. Specifically, the sodium-based or calcium-based sorbents can shift certain metals (Hg, Se, As) from the vapor phase to the solid phase. Furthermore, the characteristic leaching of these metals from fly ash can be altered when alkaline sorbent is present in the fly ash.

In this article, the chemistry of DSI and of certain hazardous air pollutant (HAP) metals in coal combustion flue gas will be presented, followed by a discussion of the currents understanding of leaching from mixtures of alkaline sorbents and fly ash.

What is Dry Sorbent Injection?

A DSI system is designed to inject of dry alkaline sorbents directly into combustion flue gas and collect of the sorbents, typically in the particulate control device or, less commonly, in the wet flue gas desulfurization scrubber. DSI systems were originally developed to reduce SO_2 emissions or SO_3 emissions. DSI chemicals can also remove HCl from flue gas, thus providing a low-cost alternative to traditional flue gas desulfurization scrubbers to some plants in order to meet HCl emission limits under the Mercury and Air Toxic Standards (MATS). The DSI systems are tailored to each location, plant and unit, to assure optimized mitigation of targeted air pollutions.

In the Mercury and Air Toxics Standards (MATS) rule for electric utility boilers, HCl was identified as a surrogate for a group of acid-gas HAPs; hence there are emission limits for HCl. Sulfur dioxide emissions are regulated by both the state and federal government. Emissions of SO_3 are regulated at the state level in some states via a restriction on condensable particulate matter. Even if SO_3 emissions are not regulated, there are compelling reasons to reduce concentrations in combustion flue gas:

1. Prevention of formation of ammonium bisulfate in air preheaters;
2. Ability to lower cold end air temperatures in the air preheater and increase boiler efficiency;
3. Better utilization of activated carbon for mercury control;
4. Reduction in corrosion in the air preheater or downstream of air preheater; and
5. Reduction of sulfuric acid mist in the stack, which can manifest as a persistent plume (“blue plume”) in the atmosphere.

Sorbents Used in DSI Technology

The primary DSI sorbents used in today’s market for acid gas control are calcium-based (hydrated lime) or sodium-based (trona, sodium bicarbonate) sorbents. The applications of these sorbents are shown in Figure 8.

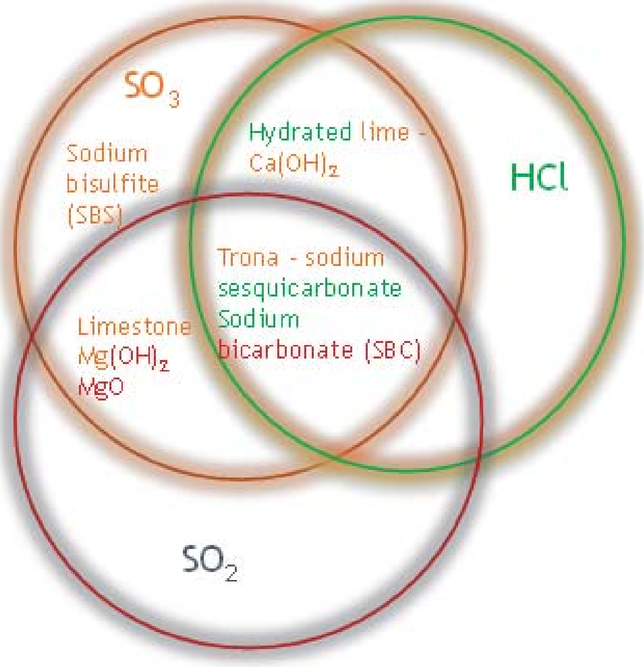

Figure 8. Applicability of Alkaline Sorbents for Acid Gas Control

In a typical DSI installation, the sorbent is injected into the flue gas, anywhere from SCR inlet to scrubber inlet depending upon the pollutants being targeted, type of sorbents and operating temperatures at injection points. Multiple injection lances are typically used in the duct; computational fluid dynamic (CFD) modeling is used routinely to optimize the lance arrangement for maximum dispersion.

The normalized stoichiometric ratio (NSR) is used to describe the ratio of moles of active sorbent element (Na, Ca) to moles of acid gases present in the duct. NSR should be calculated based on total acid gases (SO_2+HCl+HF+SO_3), because all will react with DSI chemicals to some extent. Unfortunately, NSR reporting is inconsistent; in some cases, the NSR of sorbent to a specific acid gas or sorbent usage as mass ratio (e.g., lb sorbent/lb acid gas) is reported. To compare the effectiveness of various sorbents, the flow rate of acid gases in the flue gas of interest must be calculated to estimate site specific sorbent usage.

Hydrated lime has been used to remove SO_3 and/or HCl from flue gas. Efficient removal requires a high surface area (greater than 20 m^2/g) and a small particle size (2-5 microns).

Trona typically has mean particle size between 30 and 35 µm, while sodium bicarbonate (SBC) is coarser (~50 µm). Both trona and SBC may benefit from being milled before injection. Trona and SBC decompose at about 275°F (135°C) to form sodium bicarbonate. The decomposition reaction that occurs when the sodium sorbents are injected into the flue gas produces a high surface area, allowing an efficient reaction with acid gases.

Generally the removal of acid gases follows this trend:

$$SO_3 > HCl >> SO_2$$

Sodium sorbents are more reactive with SO_2 than calcium sorbents when injection occurs post-economizer. When DSI is used to remove SO_3 or HCl from the flue gas, some SO_2 may also be removed and must be taken into account when calculating the sorbent flow rate that is needed.

Hazardous Air Pollutant Metals in Combustion Flue Gas

Coal contains many elements in trace concentrations. In this discussion, we will focus on the metals called out in Clean Air Act (CAA) as Hazardous Air Pollutants (Sb, As, Be, Cd, Cr, Co, Pb, Mn, Hg, Ni, Se) and in the Resource Conservation and Recovery Act (RCRA) (As, Ba, Cd, Cr, Pb, Hg, Se, Ag).

Most of these metals are found in the particulate form in coal combustion flue gas (i.e., as fly ash or bottom ash). The three notable exceptions to this are mercury, arsenic and selenium. These elements can be found in the gas phase in certain parts of a coal-fired boiler. Arsenic and selenium can react chemically with DSI sorbents. DSI can enhance removal of mercury by unburned carbon or injected activated carbon by reducing SO_3 in the gas. Thus, DSI might alter the disposition of these elements in the flue gas path.

Mercury, arsenic and selenium are present in coal in trace quantities, typically in the range of 0.1 to 10 µg/g. Mercury is completely converted to gaseous elemental mercury in the flame. Arsenic and selenium vaporize almost completely in the flame and leave the high-temperature zone of the coal-fired boiler as gaseous oxides. As the flue gas cools due to convective heat transfer, gaseous mercury, arsenic and selenium compounds interact with the surface of fly ash particles.

Arsenic remains in the vapor phase until the inlet of the air preheater, at temperatures above about 650°F (300°C). The presence of vapor-phase arsenic at these temperatures has caused deactivation of the catalysts in selective catalytic reduction (SCR) units. Gaseous arsenic reacts with calcium oxide, which can be seen in the data in Figure 9 showing results from three full-scale power plants where gaseous arsenic concentration was measured at the SCR inlet, with and without addition of limestone to the fuel [1]. Laboratory experiments on the reaction between arsenic oxide and lime showed the highest reactivity at about 1000°F (600°C) [2]. Thus, if hydrated lime were injected upstream of the air preheater, it could react with gaseous arsenic oxide. However, injection of hydrated lime downstream of the air preheater would not result in reaction between vapor-phase arsenic and calcium, because arsenic does not typically exist in the

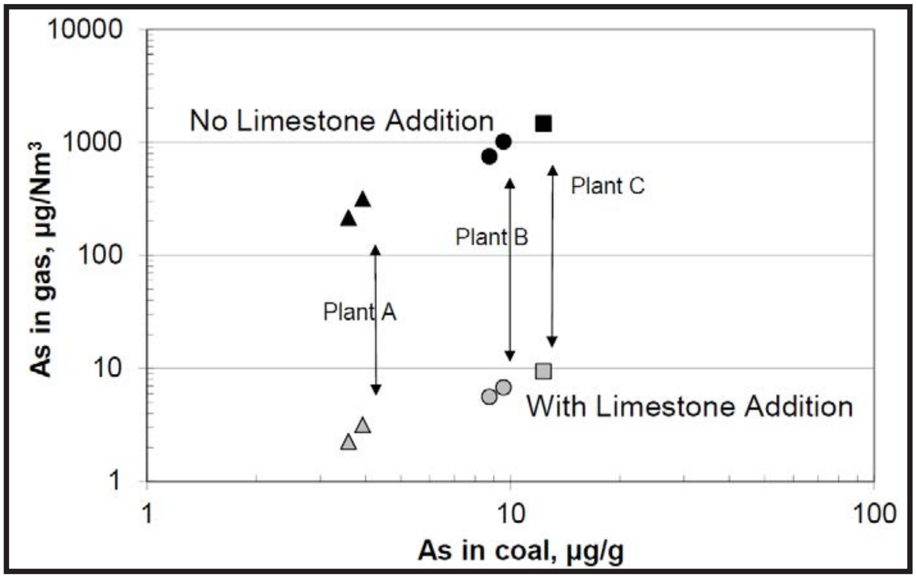

Figure 9. Gas-phase arsenic at SCR inlet temperature in three bituminous-fired boilers, with and without limestone addition to the boiler [1].

gas phase after the air preheater. Theoretically speaking, gaseous arsenic could react with sodium compounds at pre-air preheater temperatures in the flue gas, although this has not been documented as yet.

Selenium, like arsenic, vaporizes almost completely in the combustion zone, forming a stable gaseous oxide that can react with surfaces as the flue gas cools. Selenium oxide reacts with calcium and iron in the fly ash [3]. Selenium also reacts with sodium sorbents, as illustrated in Figure 10, in which experiments with sorbent injection in a quenched off-gas stream from an industrial glass furnace showed that hydrated lime was a more effective sorbent for selenium than sodium carbonate when injected at temperatures between 625°F and 735°F (330°C and 390°C) [4]. In contrast to arsenic, however, selenium forms a stable gaseous oxide down to temperatures as low as 140°F (60°C) [5]. Gaseous selenium has been shown to react with hydrated lime injected into a full-scale power plant at about 330°F (165°C) [6]. Therefore, if selenium oxide is present in the gas phase, it should react with sodium- or calcium-based DSI sorbents, whether injected upstream or downstream of the air preheater in a coal-fired power plant.

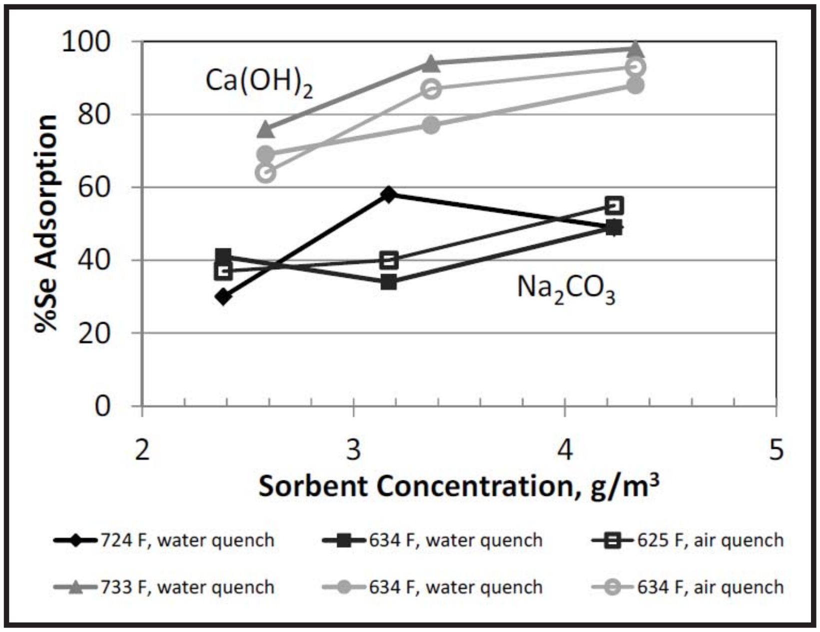

Figure 10. Removal of selenium from quenched off-gas at a glass furnace as a function of injection concentration of DSI sorbent [4].

In general, arsenic reacts with hydrated lime injected upstream of the air preheater. Selenium reacts with hydrated lime or sodium-based sorbents injected either upstream or downstream of the air preheater. These sorbents will reduce the gas-phase concentration of the metals and, in the case of selenium, shift selenium from the gas phase to the fly ash that is collected in the particulate control device.

How Does DSI Affect Metals Leaching from Fly Ash?

Dry sorbent injection may increase the concentration of mercury, arsenic and selenium in the fly ash collected by the plant's particulate collection device. Fly ash may be sold, mixed with water and sent to settling pond, or sent to a landfill. In all these cases, the amount of metals leached from the fly ash is an important characteristic in determining the disposition of the material.

Without the addition of alkaline sorbents, bituminous fly ash has been shown to leach more As and Se than subbituminous ash. In subbituminous fly ash, little As is leached. The high calcium content of subbituminous fly ash plays a role in minimizing leaching of As and Se in subbituminous ash.When hydrated lime was added to the flue gas in a pilot-scale combustor burning bituminous coal [7], selenium concentration increased in the fly ash, relative to the baseline, and TCLP leaching tests showed that selenium was the only RCRA metal to substantially increase in the leachate in the fly ash sample containing hydrated lime.

Mixtures of bituminous fly ash and sodium- or calcium-based sorbents were exposed to simulated flue gas [8] at 399°F (204°C) and the mixtures were then leached using SPLP. Leaching of arsenic, selenium and chromium increased in the mixtures containing Na_2CO_3 more than in the mixtures containing $Ca(OH)_2$ (relative to baseline). None of the other RCRA metals, including mercury, showed evidence of increased leaching as a result of the presence of either sorbent.

Fly ash has been analyzed for leaching characteristics from plants burning bituminous and subbituminous coal in which trona was injected [9,10]. Trona injection resulted in significantly more leaching of As and Se, as well as Mo and V, relative to the baseline. Similar full-scale fly ash samples containing calcium-based sorbents have not been studied to date. However, laboratory and pilot-scale testing suggests that leaching of As and Se will not increase as much when calcium sorbents are used for DSI as compared to sodium sorbents.

Conclusion

Dry sorbent injection is a low-capital cost method for compliance with emission limits on acid gases and mercury from coal-fired boilers, with operation co-benefits such as eliminating corrosion issues and blue plume. Of the metals of interest in combustion systems, some mercury, arsenic and selenium are expected to be in the vapor-phase at temperatures downstream of the economizer. Mercury removal can be enhanced by removing SO_3 from the flue gas, which competes with mercury capture by carbon. Arsenic and selenium can be removed from the flue gas directly with sodium- or calcium-based DSI sorbents, depending on the injection location. Leaching of arsenic and selenium from the fly ash increases with the addition of DSI sorbents; addition of sodium-based sorbents results in much higher leaching of these metals compared to addition of calcium-based sorbents. The addition of DSI sorbents to fly ash has not shown any increase in the leaching of mercury from fly ash. When considering the application of DSI on a particular boiler, the fate of the fly ash must be given consideration.

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Comparison of Wet and Dry Electrostatic Precipitator (ESP) Technologies

By Aaron Benedict, James "Buzz" Reynolds, Sankar Seetharama,
Siemens Energy Inc., Environmental Systems & Services

Abstract

With the recent surge in Electrostatic Precipitator (ESP) installations and future predictions of continued growth, ESP technology has been and will continue to be utilized for many applications. Wet and dry ESP technologies are similar but many questions arise as to the applicability of each technology as well as the advantages and limitations of each technology.

Siemens Environmental Systems & Services provides both wet and dry ESP technology for the utility power, cement and refinery industries as well as other industrial applications. While wet and dry ESPs retain similar high voltage and collection systems and share similar physical characteristics, many differences exist, attributable mainly to the inherent design of the technology to address various size particles. Dry ESPs are used to capture coarse, filterable particulate matter (PM_{10}) such as flyash. PM_{10} is defined by the U.S. Environmental Protection Agency (EPA) as particles smaller than 10 microns (a micron is one millionth of a meter). Wet ESPs capture sub-micron particulate matter, condensables and water mist commonly referred to as $PM_{2.5}$ (defined by the EPA as particles less than 2.5 microns). Whereas dust or flyash characteristics play a large role in the sizing of dry ESPs, this is not the case with wet ESPs as they are not dependent upon particulate resistivity.

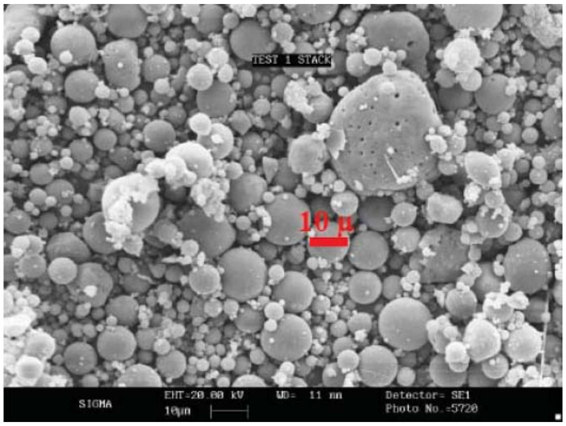


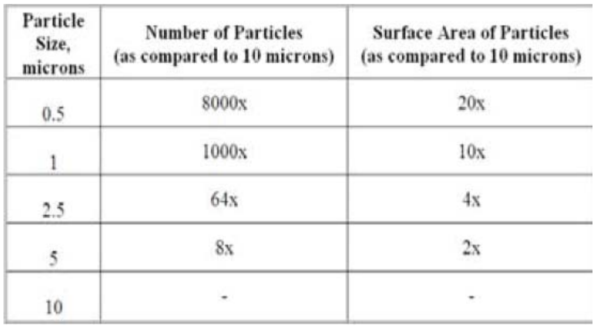
Figure 11: Varying Flyash Particle Sizes (source Clean Air Engineering)

This article compares the two technologies and Siemens' experience with the technologies. To gain a better understanding of each technology a discussion of particle size is first required.

1. Particle Size and Surface Area

As seen in Figure 11, there is a significant difference between a 1 micron particle and a 10 micron particle.

As expected, not only are smaller particles harder to capture because of their small size but there are significantly more particles to capture when dealing with fine particulate. The table in Figure 12 compares the relative number of particles that can fit within one cubic meter of gas. For the same cubic meter of gas there can be 1000 times more 1 micron particles than 10 micron particles with 10 times more total surface area!



Particle Size, microns	Number of Particles (as compared to 10 microns)	Surface Area of Particles (as compared to 10 microns)
0.5	8000x	20x
1	1000x	10x
2.5	64x	4x
5	8x	2x
10	-	-

Figure 12: Particle Size: Relative Numbers and Surface Area in 1 m^3 of Gas

To support the theoretical analysis in Figure 12 above, the charts in Figure 13 show the particle size distribution from a coal-fired utility wet scrubber on a mass basis and quantity basis (broken down by dry vs. wet for comparison). While the relative mass of "wet" particles is similar for particles sized 5 micron to 100 microns as for particles sized 0.1 to 1 micron, on a quantity basis the overwhelming number of particles are those less than 0.1 micron.

When condensable vapors cool they tend to condense on the smallest sub-micron particles because there are a greater number of small particles. The reason there has been

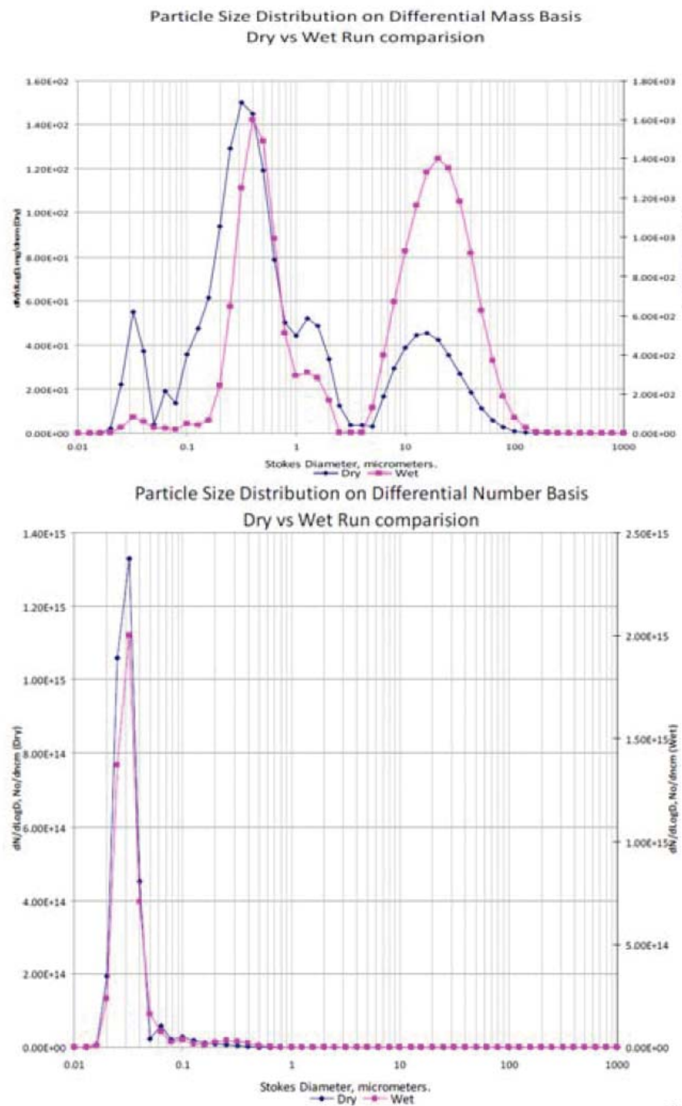


Figure 13: Dry & Wet Particle Size Distribution[1]

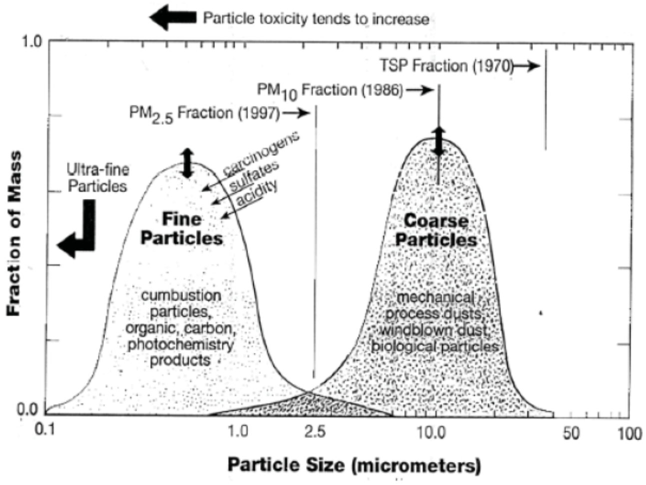


Figure 14: Particle Size vs. Toxicity (source U.S.EPA)

increasingly more focus on capturing fine particles is that these size particles are more toxic than large particles and lodge deeper in the lungs therefore posing higher health risks. Particle toxicity increases as particle size decreases as shown in Figure 14.

2. Opacity

The most visible particles are approximately a half-micron in size due to their light extinction properties. The picture in Figure 15 shows a coal-fired power plant plume that has both a dry ESP and wet scrubber installed with high visible opacity.

Figure 15: Opacity Plume

Though both air pollution control devices capture coarse particulate neither is very efficient at capturing fine particulate. The visible plume seen is from light refracting off of particles 0.1 to 1 micron in size that have passed through the dry ESP and wet scrubber; with 0.5 micron particles being the most visible[2]. The greatest contributor to this submicron particulate is sulfuric acid mist (H_2SO_4). As shown in Figure 16, opacity is directly proportional to concentration of sulfuric acid.

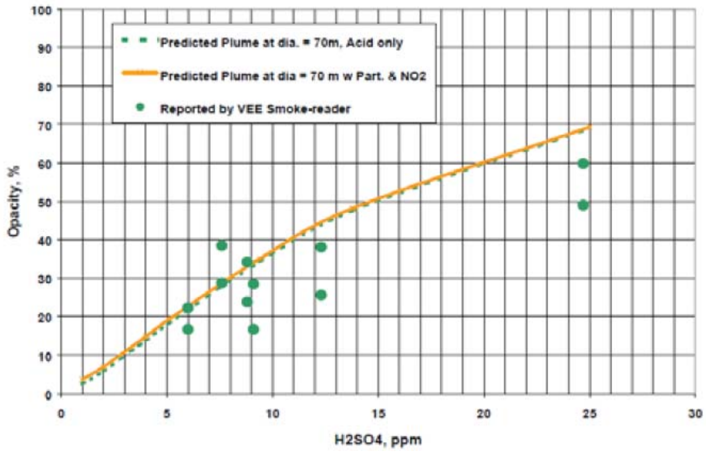


Figure 16: Opacity vs. H_2SO_4 for Large Unit with Dry ESP & Wet Scrubber[3]

3. History

The first reported ESP in commercial service was a wet ESP installed in 1907 for acid mist control. The first dry ESPs followed in the 1910's in the non-ferrous metals and cement industry. Dry ESPs in the coal-fired boiler industry went into service in 1923 at one of Detroit Edison's power plants. While dry ESPs have been in use in many industries for decades as a primary particulate control device, wet ESPs have found their use primarily in the sulfuric acid industry as a piece of process equipment to collect sulfuric acid. Not until regulatory authorities established emission limits on fine particulate matter has there been a wider need for wet ESP emission technology.

4. Theory of Operation

Dry and wet ESPs are similar in their main purpose which is to collect non-gaseous particulate from a flue gas stream. Both technologies include a multi-stage process for removal of the particulate from the gas stream by creation of an electric field (refer to Figure 17). First, a high voltage corona discharge is emitted from the discharge electrodes, ionizing the flue gas molecules between the discharge and collecting electrodes. The particulate entering this electric field are then charged by the ionized flue gas molecules and naturally attracted to the collecting electrode of opposite polarity. And finally, the collected particulate is removed from the collecting electrode.

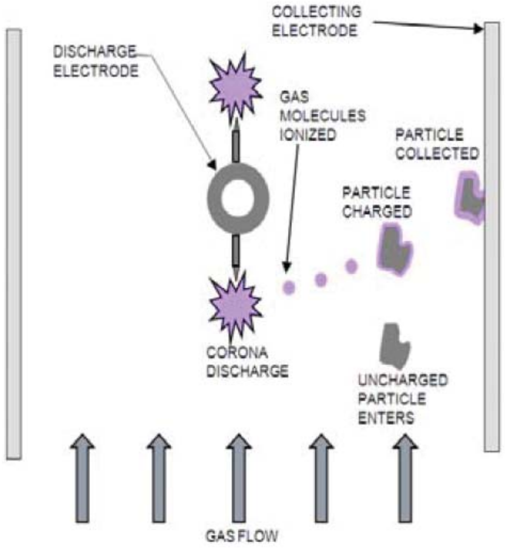


Figure 17: ESP Collection Schematic

All ESPs use this method of particulate charging and collection; the differences between dry and wet ESPs are in the process of removing the particulate from the electrodes. Dry ESPs allow the collected particulate to build-up in a layer on the collection surface, which is then removed via mechanical rapping or vibration. Many different rapping variations exist including tumbling hammer, gravity impact, vibrators, pneumatic and droprod rapping. The collected particulate falls into a collection hopper where it is removed from the dry ESP with an ash handling system. Similar rapping systems are used on the discharge electrodes to minimize potential build-up that could inhibit corona generation.

In a wet ESP, the collecting electrodes are cleaned via use of intermittent water sprays or an irrigation system preventing any build-up of particulate on the collecting electrode surface. If sprays are used, the affected electrical bus section must be de-energized to protect the transformer/rectifier sets whereas in an irrigation system the transformer/rectifiers may stay on as there is no interference with the electrical system. The water washes away the collected particulate on the collection surface. The difference in cleaning has a significant impact on function, location, operating temperature, materials of construction and performance.

5. Configuration

Dry ESP design configuration consists of a horizontal flow of flue gas between two vertical plates with discharge electrodes in the middle, commonly referred to as a "plate" ESP. Due to the large volume of gas and the heavy inlet loading of particulate that typically needs to be removed from a bottom hopper, the plate design has become the most common configuration.

Wet ESPs can come in a variety of configurations. They can be either plate or tubular; down-flow, up-flow or horizontal flow. Plate wet ESPs are very similar to dry ESPs with two vertical plates facing each other and discharge electrodes located between the plates. However, flue gas flow can be either horizontal or vertical.

Alternatively "tubular" wet ESPs (tubular collecting surfaces with electrodes in the middle) are always vertical but the flow can be either up-flow or down-flow. Additionally, tube configuration can be round, square or hexagonal. Tubular designs, with all four sides containing the flue gas offer higher efficiency per square foot of gas treated and smaller size. However, when multiple electrical bus sections are required to achieve high removal, cleaning of the collecting surface is more of a challenge in a tubular design to minimize impact on the lower bus sections with inter-stage drains. Consideration of available real estate, flue gas volume, inlet loading, required removal, sectionalization, water usage, cost and maintenance access are all factors that come into play when selecting the most appropriate wet ESP configuration.

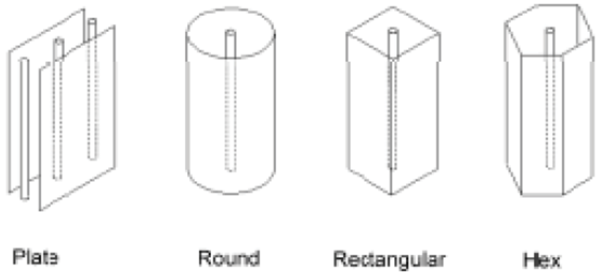


Figure 18: Wet ESP Electrode Arrangements[4]

6. Process Comparison

Dry and wet ESPs are utilized on coal-fired boilers as well as many similar industrial applications. The differences between ESPs become evident when looking at where the ESPs are installed in the process. Dry ESPs are typically the first control device to remove the heaviest load of particulate while wet ESPs are the last control device prior to the stack and act as a final polishing device.

Dry ESPs are most often installed in high ash and high temperature environments. The flue gas at this stage is most often above the adiabatic saturation temperature and the acid dew point temperature. In some older utility installations, dry ESPs were installed upstream of the air heater in a “hot-side” arrangement (temperatures of 750°F / 400°C); however this arrangement has fallen out of favor due to detrimental issues such as performance degradation over time and structural problems in many installations. Modern day utility dry ESPs are installed on the “cold-side” of the air heater at temperatures of approximately 250-350°F (120-175°C) as shown in Figure 19. Some industrial applications such as rock product kilns and catalytic cracking units still successfully use dry ESPs on temperatures of 600-800°F (315-425°C).

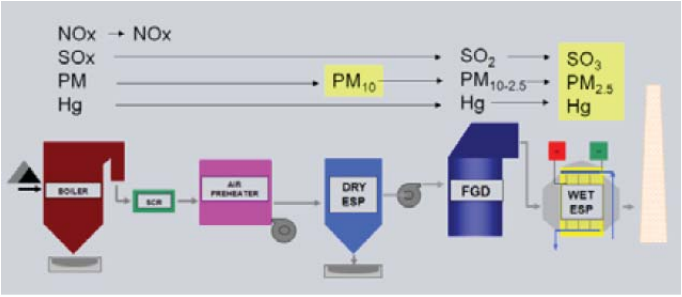


Figure 19: AQCS Schematic

Particulate loading to a dry ESP varies greatly depending upon the flyash/process; for a coal-fired boiler ranges are typically 1-10 gr/acf (2-23 g/m^3) while ranges for an oil-fired boiler are typically much lighter at <0.1 gr/acf (0.2 g/m^3). Flue gas temperature as well as particulate loading and dust (ash) composition will play a role in to how the ESP is sized.

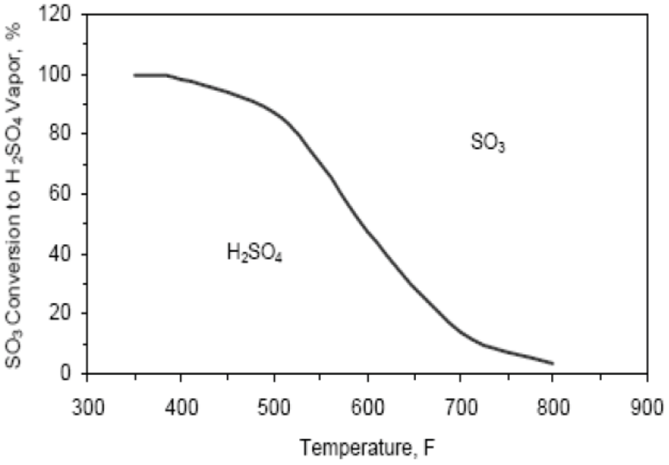


Figure 20: SO_3 Conversion to Sulfuric Acid Vapor @ 8% Moisture[5]

Wet ESPs are installed in saturated flue gas streams with considerably less particulate loading than dry ESPs. Typically, a wet ESP follows a scrubber where the flue gas is saturated to the moisture dew point (typically 130°F / 55°C) and the wet ESP is used to collect $PM_{2.5}$, H_2SO_4 and liquid droplets that remain in the flue gas after the scrubber.

In a typical utility boiler, sulfur trioxide exists in the gaseous form until the air heater where the decrease in temperature converts SO_3 to H_2SO_4 (Figure 20). While the sulfuric acid remains in vapor form through the dry ESP (approx 300°F), in the saturated flue gas stream, all sulfuric acid previously existing as a vapor condenses into an aerosol (Figure 21).

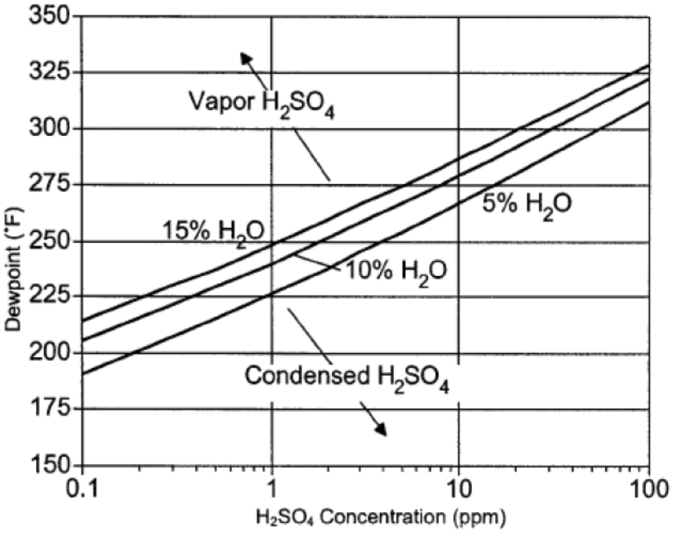


Figure 21: Formation of Condensed Sulfuric Acid[6]

The particulate loading to a wet ESP is typically much less than a dry ESP with PM of less than 2.5 microns and H_2SO_4 droplets of 0.1 – 0.3 microns. This creates an ultra-fine aerosol droplet and as the droplet sizes get smaller, the number of droplets generated for a given mass concentration increases dramatically as previously shown in Figures 12&13.

Particulate Resistivity

One of the differences between dry and wet ESPs is how the particulate resistivity affects the ESPs. In a wet ESP, as particulate is minimal and collecting electrodes are continually cleaned, particulate is immediately captured and washed from the collecting electrodes. With no particulate buildup on the collecting electrodes, potential problems with back corona are eliminated. Particulate resistivity is temperature dependent and as the temperature decreases, so does the resistivity. This makes the particulate easier to collect than with a dry ESP without the problems of particulate re-entrainment as the particulate is immediately removed when it is collected. In other words, resistivity of the particulate does not play a significant factor into the sizing of the wet ESP. Because of this, wet ESPs can be sized to higher precipitator velocities and lower specific collecting areas (SCA) than dry ESPs.

A high volume of sub-micron particulate entering the wet ESP can lead to corona or current suppression. Current suppression reduces wet ESP efficiency and can occur at particulate loadings of just 0.1 gr/acf (0.2 g/m^3). Most suppliers of wet ESPs utilize a high intensity discharge electrode to combat current suppression.

Resistivity of the particulate plays a significant role in the sizing and performance of dry ESPs. Resistivity can be broadly divided into three grades; low ($<10^9$ ohm-cm), moderate (10^9 –10^{11} ohm-cm) and high ($>10^{11}$ ohm-cm). Ideally dry ESPs prefer and operate best with particulate in the moderate range. This allows the ash layer to form on the plates and mostly shear off into the hoppers when rapped. High resistivity particulate leads to back corona where the flow of positive ions from the ash layer on the collecting plate effectively hampers the precipitator process. Low resistivity particulate, though less harmful than high resistivity, results in the ash layer quickly losing its charge and having a higher propensity to re-entrain into the gas stream during rapping.

Water Usage

Another major difference between dry and wet ESPs is the collection and disposal of particulate. Collected flyash from dry ESPs is collected as solid waste and is typically able to be land-filled, reused in the process or sold. As wet ESPs use wash water to collect the particulate on the collecting electrodes, the water demands and effluent needs to be addressed. The wet ESP can use once-through water or a recycle system with bleed incorporated. With a scrubber, the wet ESP effluent can be pumped back into the scrubber for mist eliminator wash water and with first use of the water meant for the wet scrubber, there is no additional water burden from the wet ESP. If no scrubber is present, water treatment facilities or other modifications may be required to handle the effluent.

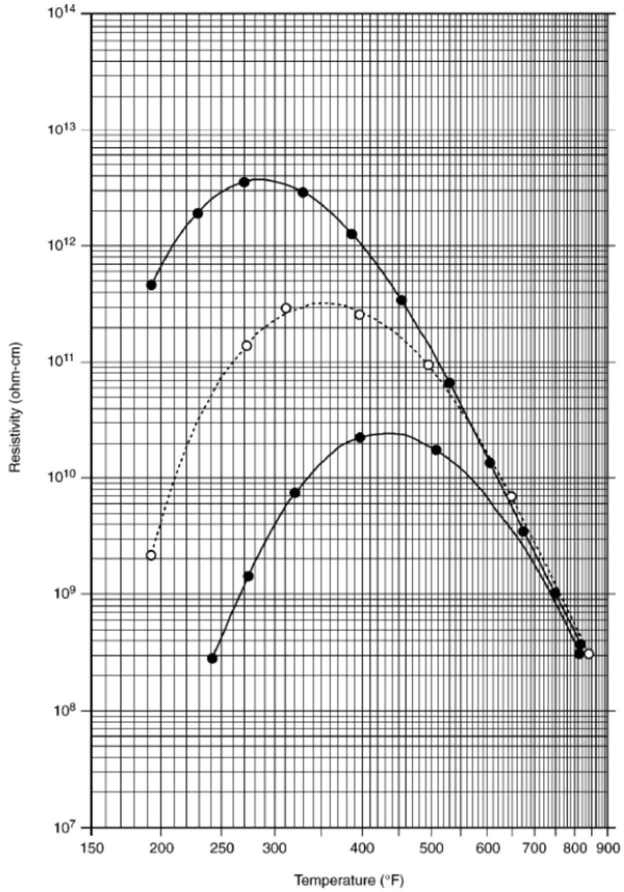


Figure 22: Resistivity Curves for Low, Moderate and High Resistive Particulate[7]

7. Installations

Dry ESPs have been installed on just about every utility and industrial process that requires removing particulate from a gas stream.

Because of the conditions that they operate under (high temperature, typically above acid dew point), dry ESPs can be fabricated from mild carbon steel making them relatively inexpensive. Internal collecting electrodes are typically gauge thickness carbon steel, and recent designs utilize unbreakable, rigid frame or rigid discharge electrodes.

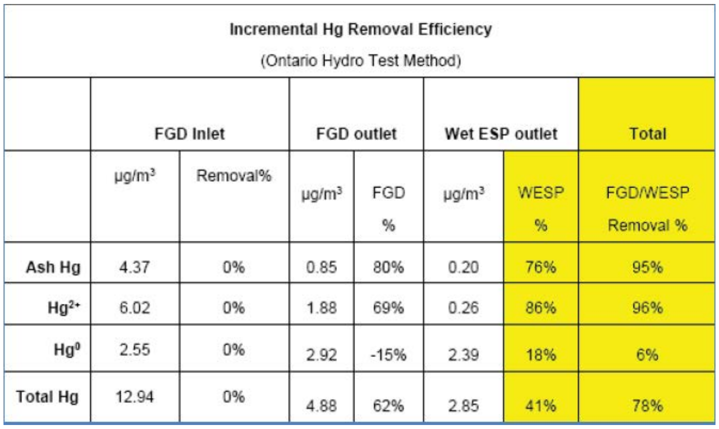
Wet ESP technology has become a standard component in the sulfuric acid industry to capture sub-micron H_2SO_4 aerosol. Wet ESPs have been employed in many different industrial applications for plume reduction associated with $PM_{2.5}$ and H_2SO_4 mist, as well as abatement of toxic metals.

Due to the saturated and high-corrosive environment in which they operate, wet ESPs are typically constructed of corrosion resistant materials such as alloy, FRP or plastics. The material chosen will have to withstand the concentration of acid gases and sulfur oxides in the flue gas stream as well as temperature surges. While physically smaller than a dry ESP, the materials of construction make the wet ESP more expensive.

8. Mercury Control

In recent years in the U.S., mercury emissions regulations have gone into effect throughout utility and industrial sectors. In flue gas, mercury exists as either a vapor or particulate. Vapor phase mercury is further broken down into elemental mercury (Hg^{o}) and oxidized mercury (Hg^{2+}), which is water soluble. Particulate mercury (Hg^{P}) exists as a solid. In dry ESPs, particulate mercury may be captured but any elemental or oxidized mercury will pass through. However, vapor phase mercury can be captured in a dry ESP with the use of an activated carbon injection system. These systems inject activated carbon into the ductwork upstream of the dry ESP which allows the activated carbon to adsorb the vapor phase mercury into its pores. These systems can achieve mercury removal efficiencies of 90%+.

There has been very limited testing of mercury removal through a wet ESP. However, the testing that has been performed has shown that a wet ESP will capture any particulate bound Hg as $PM_{2.5}$ with high efficiency as well as some oxidized mercury. Interestingly, a small fraction of elemental mercury was found to oxidize within the wet ESP, which most likely occurs from the reaction with ozone generated within the wet ESP. Therefore, a wet ESP can enhance mercury capture as a secondary free co-benefit.



Incremental Hg Removal Efficiency (Ontario Hydro Test Method)							
	FGD Inlet		FGD outlet		Wet ESP outlet		Total
	µg/m³	Removal%	µg/m³	FGD %	µg/m³	WESP %	FGD/WESP Removal %
Ash Hg	4.37	0%	0.85	80%	0.20	76%	95%
Hg^{2+}	6.02	0%	1.88	69%	0.26	86%	96%
Hg^{0}	2.55	0%	2.92	-15%	2.39	18%	6%
Total Hg	12.94	0%	4.88	62%	2.85	41%	78%

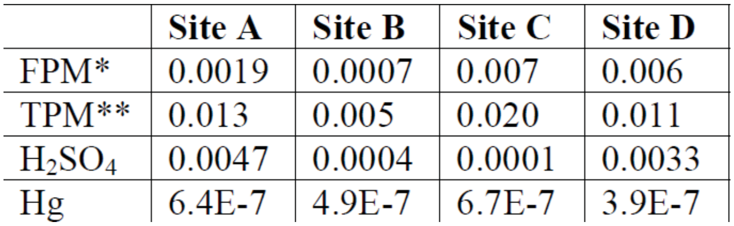
Figure 23: FGD/Wet ESP Hg Removal[8]

9. Performance

Both wet and dry ESPs are cable of high efficiency removal. Dry ESPs have consistently demonstrated 99%+ removal efficiencies for filterable PM_{10} and certainly in the 90+% range for filterable $PM_{2.5}$. However, $PM_{2.5}$ generated also contains condensables that the dry ESP cannot remove as they exist as vapor at the high temperatures that dry ESPs operate within.

Wet ESPs have demonstrated 99%+ removal of total $PM_{2.5}$ (filterable and condensable), droplets and H_2SO_4 as well as having some mercury removal as indicated in the previous section. Current-day state of the art power plants have recognized the advantages of installing both dry and wet ESPs in the air quality control system where there is a wet scrubber installed.

Siemens has provided dry ESPs and wet ESPs in series on three (3) large utility coal-fired boilers and one (1) coal-fired utility with a fabric filter and wet ESP in series. Performance results are provided below in Figure 24. Site "A" air pollution control consists of hydrated lime injection, activated carbon injection, fabric filter, wet scrubber, wet ESP. Site "B" APC consists of dry ESP, hydrated lime injection, activated carbon injection, fabric filter, wet scrubber, wet ESP. Sites "C" and "D" APC consist of hydrated lime injection, activated carbon injection, dry ESP, wet scrubber, wet ESP.

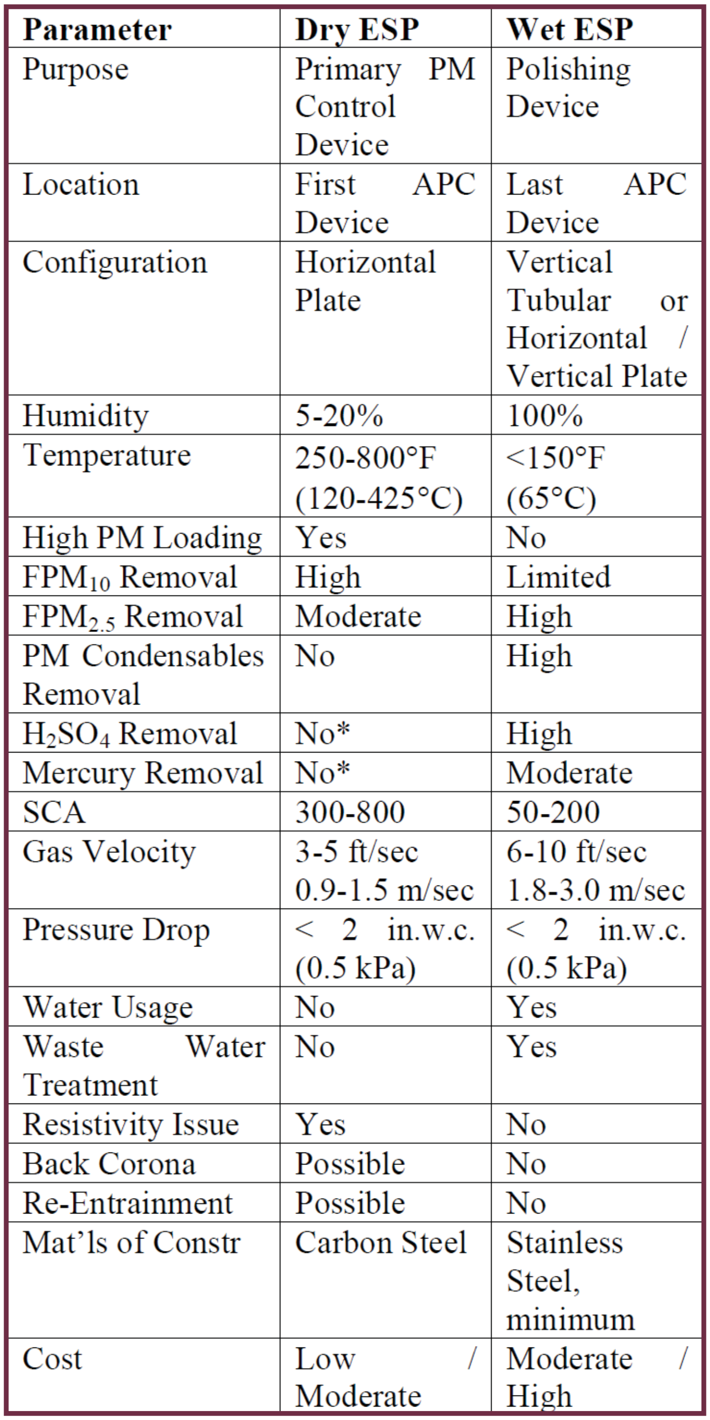


	Site A	Site B	Site C	Site D
FPM*	0.0019	0.0007	0.007	0.006
TPM**	0.013	0.005	0.020	0.011
H_2SO_4	0.0047	0.0004	0.0001	0.0033
Hg	6.4E-7	4.9E-7	6.7E-7	3.9E-7

*Filterable particulate
**Total particulate (filterable and condensable)

Figure 24: Stack Emissions Results in lb/MMBtu

As can be seen in the table above, the wet ESP acts as a final polishing device providing near-zero emissions. Also note that with the future possibilities of carbon dioxide regulation, sites with a wet ESP installed are "CO_2 ready" as CO_2 scrubbing requires very low inlet pollutants of particulate matter, sulfuric acid SO_2, etc.



Parameter	Dry ESP	Wet ESP
Purpose	Primary PM Control Device	Polishing Device
Location	First APC Device	Last APC Device
Configuration	Horizontal Plate	Vertical Tubular or Horizontal / Vertical Plate
Humidity	5-20%	100%
Temperature	250-800°F (120-425°C)	<150°F (65°C)
High PM Loading	Yes	No
FPM$_{10}$ Removal	High	Limited
FPM$_{2.5}$ Removal	Moderate	High
PM Condensables Removal	No	High
H_2SO_4 Removal	No*	High
Mercury Removal	No*	Moderate
SCA	300-800	50-200
Gas Velocity	3-5 ft/sec 0.9-1.5 m/sec	6-10 ft/sec 1.8-3.0 m/sec
Pressure Drop	< 2 in.w.c. (0.5 kPa)	< 2 in.w.c. (0.5 kPa)
Water Usage	No	Yes
Waste Water Treatment	No	Yes
Resistivity Issue	Yes	No
Back Corona	Possible	No
Re-Entrainment	Possible	No
Mat'ls of Constr	Carbon Steel	Stainless Steel, minimum
Cost	Low / Moderate	Moderate / High

*Unless treated with sorbent injection

Figure 25: Summary of the discussion points

10. Summary

Dry and wet ESPs can be utilized effectively for high efficiency removal. In order to maximize their effectiveness, it is important to understand the advantages and limitations of the technologies. The Figure 25 provides a summary of the discussion points presented above.

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SIEMENS

Can Dry Sorbent Injection Technology Really Work for HCl for MATS Compliance?

By Michael Thiel, Nol-Tec Systems

The Environmental Protection Agency (EPA) has been working for many years to develop and execute stricter standards for energy generating units' (EGUs) pollution mitigation. Standards have finally been established and now EGUs need to find solutions that meet the mitigation standards, as well as make sense for cost effective and efficient running of their plants. Dry sorbent injection (DSI) systems are showing proven ability to meet the new EPA standards and should be considered as a means to come into compliance.

Figure 26: In field tests, DSI is proving its ability to meet new EPA standards.

A Summary of the Standards

The Clean Air Act, greatly expanded in the early 1990s, gave the EPA greater authority to enact and implement pollution mitigation standards throughout the United States. The EPA works closely with states, Native American tribes, local governments, and businesses to develop standards that are achievable and can be maintained over the long run. These standards, once referred to as the application of maximum achievable control technology (MACT), are now finalized as Mercury and Air Toxics Standards (MATS). The final rule was published on December 21, 2011. EGUs have three years to comply with the final standards, with a one year extension possible for final installation of the new technology.

MATS applies to EGUs larger than 25 megawatts (MW) that burn coal or oil for the purpose of generating electricity for sale and distribution through the national electric grid to the public. It establishes numerical emission limits for mercury, particulate matter (a surrogate for toxic non-mercury metals), and hydrochloric acid (HCl) (a surrogate for all toxic acid gases). It also creates alternative numeric emission standards, including SO_2 as an alternate to HCl.

The focus of this article is HCl and SO_2. The specific limit for HCl is 0.0020 lbs/MMBtu. For SO_2, the limit is 0.20 lbs/MMBtu. Dry Sorbent Injection (DSI) has been proven to meet these standards in real world tests and permanent installations. Before we examine those test results, we'll discuss the basics of DSI.

Basics of Dry Sorbent Injection

DSI uses a pneumatic conveying system to inject dry sorbent materials into system ductwork in a controlled manner. The pollutants in the plant emissions interact with the sorbent material and become inert or non-polluting. Sorbents include hydrated lime, powdered activated carbon, sodium bicarbonate (SBC) and trona. The main pollutants mitigated with DSI include SO_2, SO_3, Hg, and HCl emissions.

DSI systems are designed to meet each of the power plants specific needs. The precise injection rate needed can be estimated based on unit specification, coal properties, duct work, and the desired level of removal, in conjunction with field data. Silos are sized to that injection rate and the number of days of storage a customer needs. Mills can be added, to refine the sorbent material to the most effective size to capture the emissions the plant is mitigating. Milling of the sorbent can greatly increase the removal efficiency of the pollution. And that means less sorbent is needed, decreasing costs. For example, if 10,000 lbs./hour of a rough sorbent were typically injected, only 7,000 lbs./hour of that sorbent in a milled state might be needed. It's important that your DSI system provider looks at these types of unique circumstances to ensure a cost efficient system is designed and installed.

The use of DSI technology as an industry standard for air pollutants began with SO_3 systems to eliminate the "blue plume" that EGUs experienced when running selective catalytic reductions (SCRs). Today, DSI is an industry standard for SO_3. Now, DSI is being applied to other pollutants such as HCL and SO_2.

The type of mill used would depend on the material to be refined and the precision that is required in the final milled sorbent. Pin mills are fairly common and have typically been used for Trona applications. But other suppliers use proven air classify milling (ACM) technology for Trona and SBC. A single ACM unit can typically achieve up to 4 TPH. It utilizes an exhauster fan to pull a vacuum on the mill and move the sorbent material from the mill to a vacuum receiver, where it is then discharged into the convey line, which conveys the sorbent to the system ductwork. Nol-Tec is able to guarantee a d90 < 25 micron size on the SBC. This ensures a more efficient mitigation of the pollutant. Another advantage of the ACM technology is a tighter distribution of particle size, since the material is classified prior to exiting the mill. With a pin mill style technology, the material has a single pass-through, giving a larger distribution of particle size.

Why use DSI for HCl mitigation?

There are a number of reasons an EGU would want to consider utilizing DSI to meet MATS standards. One of the most attractive reasons is that DSI can be a low capital cost solution. It allows EGUs to supplement their current mitigation systems affordably – or to use DSI as an interim solution until larger, more costly solutions can be evaluated and installed, if needed.

Additionally, DSI systems can be quickly installed and started up. Often, the time frame from purchase order to commissioning is less than one year. The time frame variability is based largely on the market and amount of projects being executed by utilities. A relatively quick project execution for DSI systems can allow EGUs to quickly meet the EPA standards, even while they are seeking funding or the necessity of some additional type of solution.

DSI has been demonstrated to be effective for HCl removal. As we will see in the example results that follow, Nol-Tec Systems has proven results from real world testing of our own DSI systems.

Good candidates for DSI mitigation

There are a number of contexts that must be considered, when determining whether DSI will be effective in a power plant's mitigation process. An EGU with an existing SO_2 wet scrubber may find that the scrubber alone is insufficient to meet the 99+% HCl removal requirement. DSI could supplement the scrubber and bring the plant into compliance.

In coal-burning units, the sulfur content of the coal and the boiler size must be considered. The amount of sulfur in the coal sulfur impacts the SO_2 levels. And SO_2 levels impact HCl removal with sodium sorbents. The combination of sulfur content in the coal and the boiler size (amount of coal being burned) sets the amount of SO_2 in the flue gas. These parameters must be considered when looking at DSI for HCl. In the case of hydrated lime, only a small amount of reagent reacts with SO_2 so the sulfur content is less of an issue.

Residence time of the emissions within the system must be considered. The longer the residence time, the more likely the air pollutants will react with the sorbent. Residence time is dependent on flow rate of the emissions and the duct configuration of the system.

The particulate control device (PCD) may also impact the decision to use DSI. A pulse jet fabric filter (PJFF) PCD allows for high residence time because of the filter cake of sorbent on the bags. This in turn increases the removal efficiency of the air pollutant. This allows for lesser amounts of sorbent to be used to achieve the desired removal of pollutant. This factor may help promote DSI technology.

Lastly, each EGU is different in how it operates in accordance with "the grid". Some EGUs operate in a base load manner. These units desire low operating costs so they may be less apt to choose DSI, because of the ongoing cost of the sorbent. If an EGU operates in a peak load fashion, then it suffices to use a low capital cost solution and deal with the sorbent costs. Simply turn on the DSI when HCl levels rise to bring them back into compliance.

With these considerations in mind, there are a number of good candidates for DSI pollutant mitigation. Smaller, coal-fired units, or any unit that uses low sulfur coal, have achieved high success rates with DSI mitigation for HCl and SO_2. We have found that all units are good candidates for SO_3 mitigation.

Testing DSI in Your System

Dry sorbent injection is an excellent solution for many applications. It will be used by many EGUs to achieve HCl emission limits. However, the best way to determine whether it is a good solution for your plant is to test a DSI system in your plant location, mitigating your actual emissions.

It is important to work with a DSI supplier who can provide portable test systems that can be incorporated into your own EGU system. Such on-site testing can give you confidence that DSI will ensure your system will meet EPA standards in a timely and cost-effective manner.

An Example of Test Results

Nol-Tec Systems has performed a number of on-site tests for a variety of EGUs. In this example, we will examine a bituminous coal-fired unit with a boiler that is smaller than 150 MW, utilizing an economizer, air pre-heater, and electrostatic precipitator (ESP). The sulfur content in the coal is about 1.2%. Residence time of the emissions in the system is under one second, which is less than ideal.

This unit is a difficult application, for several reasons. The sulfur levels in the bituminous coal impact the mitigation. The low residence time and low mix rate the system has also present challenges. And the PCD is an ESP which does not allow further mitigation, unlike the PJFF which utilizes a filter cake for further mitigation after it reaches the PCD.

The primary objective of this test was to determine whether the new MATS HCl limit could be achieved on this boiler. With that objective and the system's challenges in mind, Nol-Tec engineers designed a test system to meet that goal, using CFD modeling services. They determined the best location for the injections of sorbent to be made (at the economizer outlet at 600-700°F). Sorbent amounts were calculated and two types were tested. SBC and trona injection were each done for two days out of each week.

Test Results

Trona and SBC proved to mitigate HCl to MATS limit of 0.002 lbs/mmBtu. This chart, showing percent of HCl removed in relation to the amount of sorbent injection injected, is "Total Nominal Stoichiometric Ratio (NSR)" meaning both SO_2 and HCl are taken into account when calculating the NSR value. On the y-axis, we have the percent of HCl removed (please note that the y-axis starts at 86%.) The level we are looking for is greater than 98%, which is shown with the solid red line. At medium load, we achieved the 98% removal more consistently, using lower injection rates. At higher load, it was more difficult. Though there may be several reasons, one may include residence time as the main contributor.

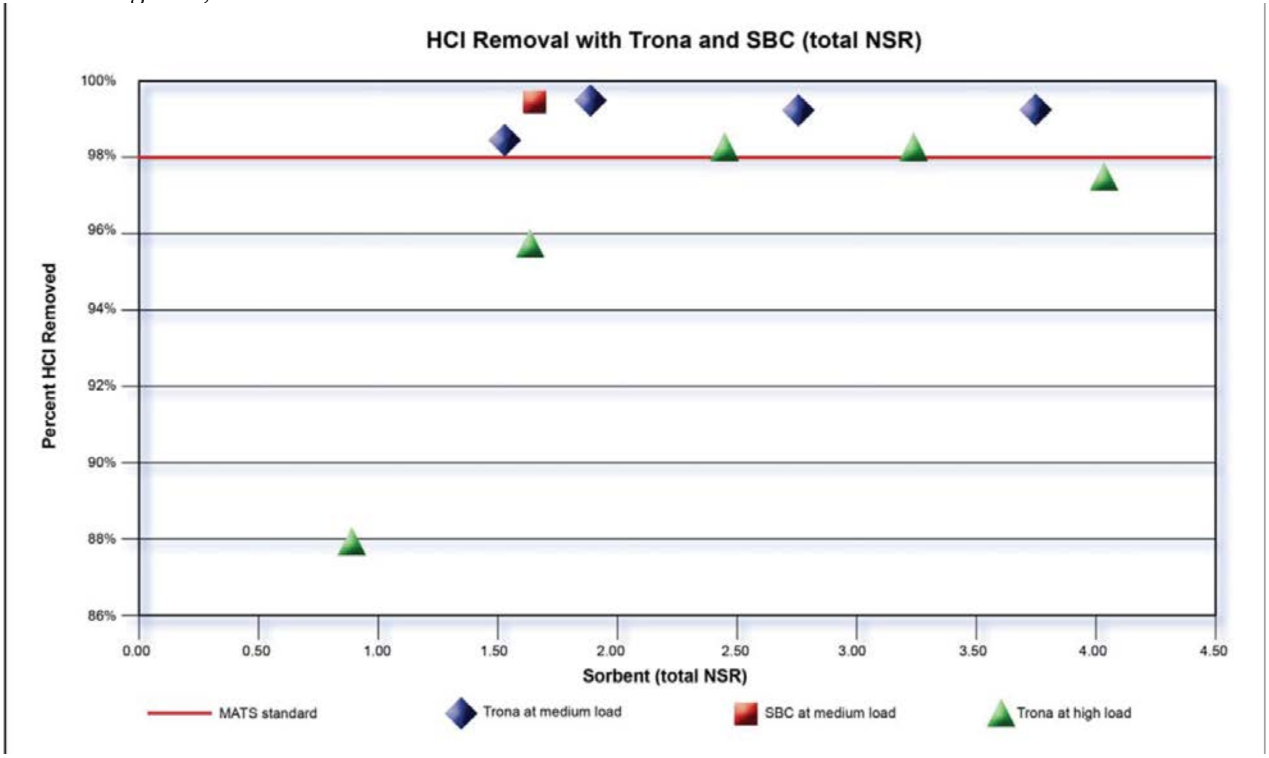

Figure 27: HCl Removal with Trona and SBC (total NSR)

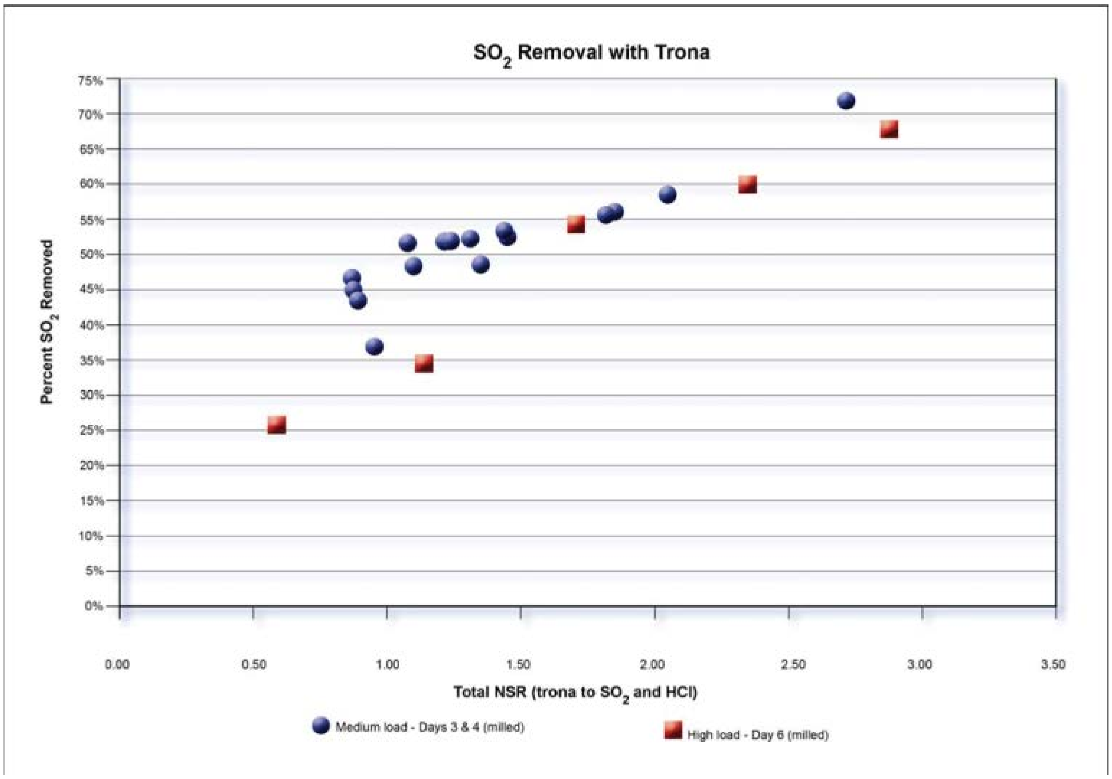

Figure 28: SO$_2$ Removal with Trona

DSI Technology Works

As we have seen with the results above, and with additional testing that Nol-Tec has done, DSI technology can indeed work to bring HCl levels into MATS compliance. It is important to note that many issues factor into a decision about using DSI for mitigation. It is important to select your mitigation partner carefully, to ensure they have the expertise or equipment to fully explore and test all the variables that can impact your decision. With due consideration to all factors, DSI technology can bring EGUs into compliance with MATS regulations in an efficient and cost effective manner.

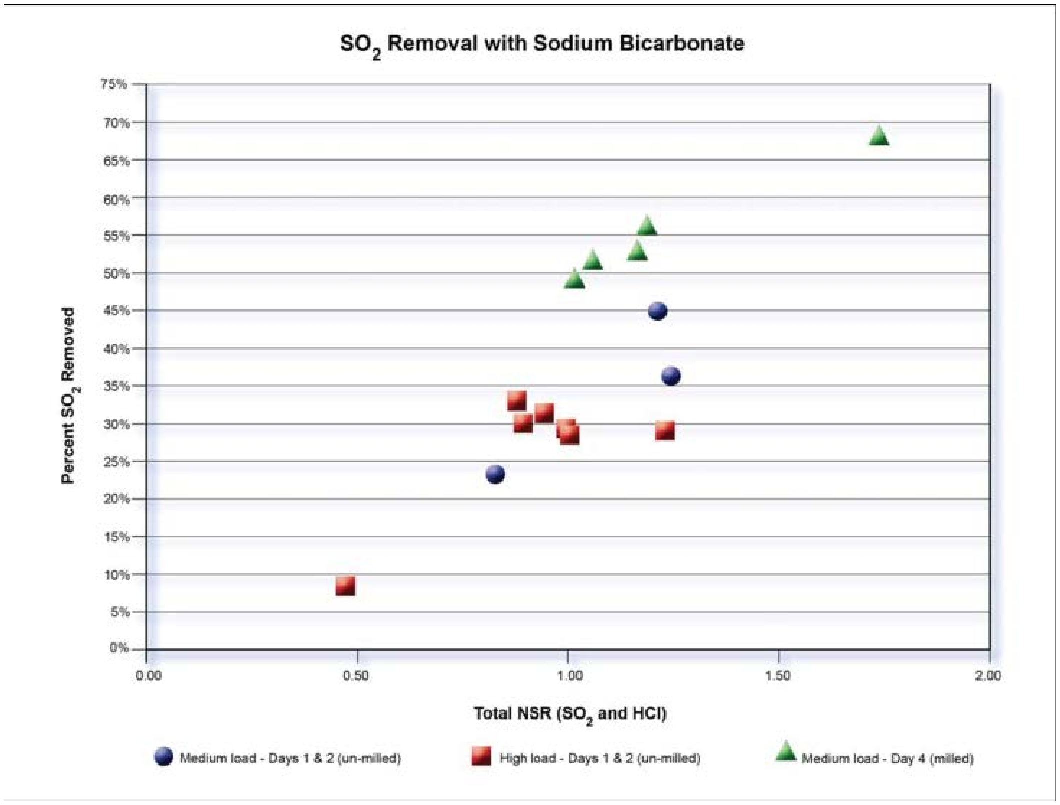

Figure 29: SO$_2$ Removal with Sodium Bicarbonate

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