

## ***Executive Summary***

### **Treating Bottom Ash Transport Water with Enhanced Wastewater Technologies**

*Written by Kevin L. McDonough, UCC*

The implementation of the 2015 Coal Combustion Residual (CCR) rule and the Effluent Limitations Guidelines (ELG) have required numerous utilities to move forward with plans and projects to address the new groundwater and surface water regulatory requirements, with particular attention to bottom ash transport water and bottom ash impoundment closure. This article is a case study of the successful implementation of state-of-the-art technologies for combined bottom ash dewatering and transport water clarifying system utilizing remotely located submerged flight conveyors and clarifiers.

***Full Story....***

### **Reducing Minimum Load Operation for the SCR and Improving System Reliability**

*Written by Suzette Puski, Babcock Power*

Several utilities are being challenged to operate their SCR systems at lower loads to balance renewables. Multiple options exist to reduce Operating & Maintenance, increase system reliability and reduce minimum load limits. It is important for the utility to understand the value of reduced load operation to properly evaluate what options to implement.

***Full Story....***

### **HRSG Ammonia Injection Optimization**

*Written by Matt Gentry, Airflow Sciences Corporation*

For Heat Recovery Steam Generators (HRSGs) the goal of minimizing CO and NO<sub>x</sub> emitted from the plant must be achieved while injecting the minimal amount of ammonia to avoid discharge out the stack. This article describes the redesign and installation of a new ammonia injection grid (AIG) to improve the emissions at western U.S. plant with two HRSG units, based on a computational fluid dynamics (CFD) flow study to analyze the current system and recommend design changes.

***Full Story....***

### **Dry Sorbent Injection: A Solution to SCR MOT**

*Written by Dylan Hardy and Grace Whiteford, Nol-Tec Systems*

The current demand for utilities requires total plant optimization. To accomplish this, plants are experimenting with dry sorbent injection locations to meet lower baseload requirements. One method explored is pre-SCR injection paired with lanceless injection technology (Sorb-Tec). Testing has resulted in high acid gas removal and has shown that moving DSI upstream of the SCR is a viable solution for an increase in flexibility that power plants hope to achieve.

***Full Story....***

### **BOF ESP Enhancement**

*Written by Mike Volker, Schenck Process*

At a Basic Oxygen Furnace (BOF) at an Illinois steel mill, gases generated during the BOF charge and blow operations are routed to two ESPs utilizing a common inlet duct. The ESPs were unbalanced and unreliable. This article details data analysis and performance calculations which were completed which resulted in the sectionalization and adding of power supplies to the second ESP to maintain a balanced and even collection level. These enhancements increased the reliability of the unit and eliminated production delays due to down time.

***Full Story....***

## *Executive Summary (cont.)*

### Overview of Mercury Control Approaches Used by U.S. Plants

*Written by Sharon Sjoström, ADA-ES, Inc and Connie Senior, formerly with ADA-ES, Inc*

Most U.S. electric generating units (EGUs) now have at least two years of experience managing plant operations to meet the compliance Limits of the final Mercury and Air Toxics Standards (MATS) rule. This article analyzes and summarizes data reported to the U.S. Energy Information Administration (EIA) and the U.S. Environmental Protection Agency (EPA) regarding mercury compliance choices and relative effectiveness for the various types of coals, pollution control devices and mercury control additives.

*Full Story....*

## Treating Bottom Ash Transport Water with Enhanced Wastewater Technologies

*Written by Kevin L. McDonough, UCC*

Since 2015, with the implementation of the Coal Combustion Residual (CCR) rule and the Effluent Limitations Guidelines (ELG), numerous utilities have moved forward with plans and projects to address the new groundwater and surface water regulatory requirements, with particular attention to bottom ash transport water and bottom ash impoundment closure.

In the recent past, UCC has been contracted to provide wet-to-dry ash conversion and wastewater management/treatment technologies on 53 plants covering 114 operating units. As of the date of this publication, approximately half of the U.S. coal fleet has now converted traditional wet bottom ash systems to either dry handling systems or closed-loop recirculation systems.

Relative to the unique operating conditions and design

aspects of each plant, UCC has pursued a technological approach of “one size does not fit all,” and each plant must be evaluated for its own particular set of operating parameters, physical conditions and design criteria. Figure 2 on page 2 includes a typical list of design criteria commonly used for evaluating bottom ash conversion and ash wastewater technology selection.

### CASE STUDY

For a given plant in the southern region of the U.S., a utility was faced with the challenge of converting a wet bottom ash sluicing conveying system that covered multiple operating units. The existing system combined conveying lines from the different operating units into two sluice lines that directed the bottom ash slurry to a receiving pond, where the bottom ash dropped out of suspension via gravity settling.

The transport water was further clarified over the remaining area of the pond, allowing finer particulate to settle out relative to Stoke’s Law principles. In between sluice conveying cycles, the bottom ash was excavated from the pond and allowed to de-water prior to transport to a dry landfill facility.

Given the complexity of the multi-unit sluice system and associated water balance, along with some uncertainty relative to legal challenges and possible modifications to the ELG, the owner wanted to implement a



*Figure 1: CDR System at night.*

Budget	Plant Water Balance Considerations
Outage Requirements	Ash Conveying Capacities
Physical Parameters	Conveying Distance Considerations
Site Environmental & Wastewater Management Considerations	Operations & Maintenance Issues
Ash Characteristics	Multiple Unit Synergies
Ash Marketability/Beneficiation	Unburned Carbon Concerns

*Figure 2: Bottom Ash Transport Water Project Design Criteria*

technology solution that gave them maximum operating flexibility for current regulatory requirements and potential future revisions. As with any project, the technology options were reviewed relative to the design criteria noted in Figure 2, with particular emphasis on available budget and desired performance requirements.

**PROJECT GOALS**

In particular, this project required the new bottom ash dewatering and wastewater treatment technologies to meet the following operating criteria.

- Receive and process 2,700 gpm under typical conditions (normal flow)
- Receive and process up to 5,400 gpm (maximum flow)
- Dewater bottom ash to approximately 15-20 percent moisture (target is generally based on Paint Filter Test requirements and ensures sufficient moisture to limit potential fugitive dust emissions and for optimal landfill compaction)
- Achieve 30 ppm Total Suspended Solids (TSS) on a 30-day rolling average
- Achieve 100 ppm daily maximum TSS
- Maintain a pH between 6 and 9
- Utilize existing sluice pumps for bottom ash conveying from the hoppers

In addition, the system had to:

- Meet current discharge requirements (assumes final ELG allows discharge of bottom ash transport water, subject to ongoing U.S. EPA review with expected confirmation by December 2018);
- Be readily capable of being converted to a closed-

loop, zero liquid discharge system by producing a water quality suitable for feeding existing high-pressure, clean water sluice pumps;

- Ideally produce water quality that would allow for potential reuse/makeup in the plant’s wet flue gas desulfurization (WFGD) operations.

**SUMMARY OF SYSTEM AND PROCESS EQUIPMENT**

After evaluating several dry conversion alternatives, including traditional dewatering technologies and dry handling options, the plant selected a combination bottom ash dewatering and transport water clarifying system that featured remotely-located Submerged Flight Conveyors (R-SFC) and circular clarifiers with internal rake mechanisms. In particular, the selected system included two processing trains, one primary and one fully redundant standby, that could receive the bottom ash slurry (ash and transport water) from the two operational conveying lines with crossover capabilities to either process train.

A primary driver in the technology selection was the cost benefit of a system with multiple-unit synergies, whereby more than three operating units could be directed to this fully redundant system without needing to make changes within the powerhouse and under each operating unit. In addition, all construction activities could be executed in a remote location and without the need for a planned outage, thereby providing greater schedule flexibility and reduced installation costs.

The first phase of the system featured the patented technology known as the Continuous Dewatering Recirculation (CDR) System with Integral Coal Combustion Residual High Flow Plate Separator (Ref. US Patent No. 9,776,106 B2), which is now being used widely throughout the U.S. coal fleet for the management of bottom ash dewatering and bottom ash transport water treatment.

In this first phase, the bottom ash sluice lines are directed into the R-SFC where the flow enters a baffle-ring assembly that impacts on abrasion-resistant receiving plates to dissipate the energy and force the larger and coarser particulate to readily drop out of suspension. The collected solids are transported via a dual-chain scraper operation along the length of the submerged bottom of the R-SFC, up an inclined dewatering ramp before discharging into a dry, three-walled concrete bunker.

The partially clarified water is then directed under a series of chambers where the water is directed upward through sets of narrowly spaced lamella plates. As the water flows in between each pair of plates, the particulate with a specific gravity greater than water will settle onto the top surface of each lower plate. After settling onto the lower plate, the particles will slide down the surface of the plates and settle out

in the lower section of the R-SFC.

The enhanced settling performance of the lamella plate design has the following direct benefits on system performance:

- Reduced solids carryover to the clarifier, thus maximizing its settling efficiency;
- Reduction or elimination of particle neutralizing coagulant in secondary phase (clarifier) to enhance fine particulate settling performance;
- Reduction of flocculent consumption in secondary system phase (clarifier) to remove fine particulate.

The clean water then continues to travel upward and exits at the top of the lamella plates where it is directed to a series of internal troughs that ultimately exit the R-SFC and overflow into the secondary phase of the system — the clarifier.

The clarifier design approach utilized was largely based on client specifications of material properties, laboratory testing and analysis of representative samples, and the target TSS outlet concentrations. Material samples (e.g., bottom ash/economizer ash) are tested for particle size distribution and specific gravity. Settling velocities are determined mathematically and through experimental testing to size the

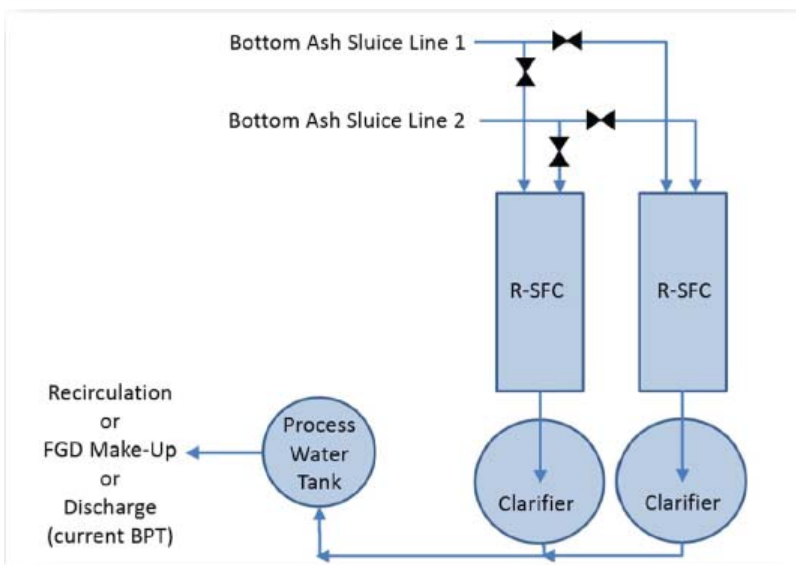
R-SFC with lamellas and the clarifier.

Detailed study is conducted to achieve a clear water overflow from the top of the clarifier, while preventing undue compaction of agglomerated solids in the clarifier bottom to mitigate the risk of plugging the slurry outlet and/or tripping the internal rake.

The system also includes chemical injection skids that introduce flocculent for fine particle agglomeration and enhanced settling. This polymer is injected into the drain piping between the R-SFC and the clarifier and then fully mixed with the water in the clarifier center feed well. As particulate settles in the clarifier, the agglomerated solids are directed via a low-velocity raking mechanism to the discharge outlet at the bottom center of the clarifier.



*Figure 3: CDR System at night.*



*Figure 4: System*

The outlet size and associated piping is uniquely engineered to remove the slurry at a reduced velocity that does not upset the agglomerated solids (i.e., limits the breaking of flocculent bonds). Pump sizes and pipe diameters are specifically selected to reduce the risk of plugging in the slurry lines. The slurry is then pumped from the clarifier outlet to the idle R-SFC, where it is added to the coarse bottom ash and then conveyed up the dewatering ramp and discharged into the dry concrete bunker for final transport to a landfill.

**PERFORMANCE RESULTS**

After an extended period of operation, including periods of varying fuel types and boiler loads, the system has met all performance guarantees. In particular, the effluent water quality has consistently remained well below the daily maximum and monthly average TSS target. In addition, the discharge water has remained slightly basic with a pH range of 7.5 to 8.5, and an average of 8.0.



*Figure 5: CDR System Day 2*

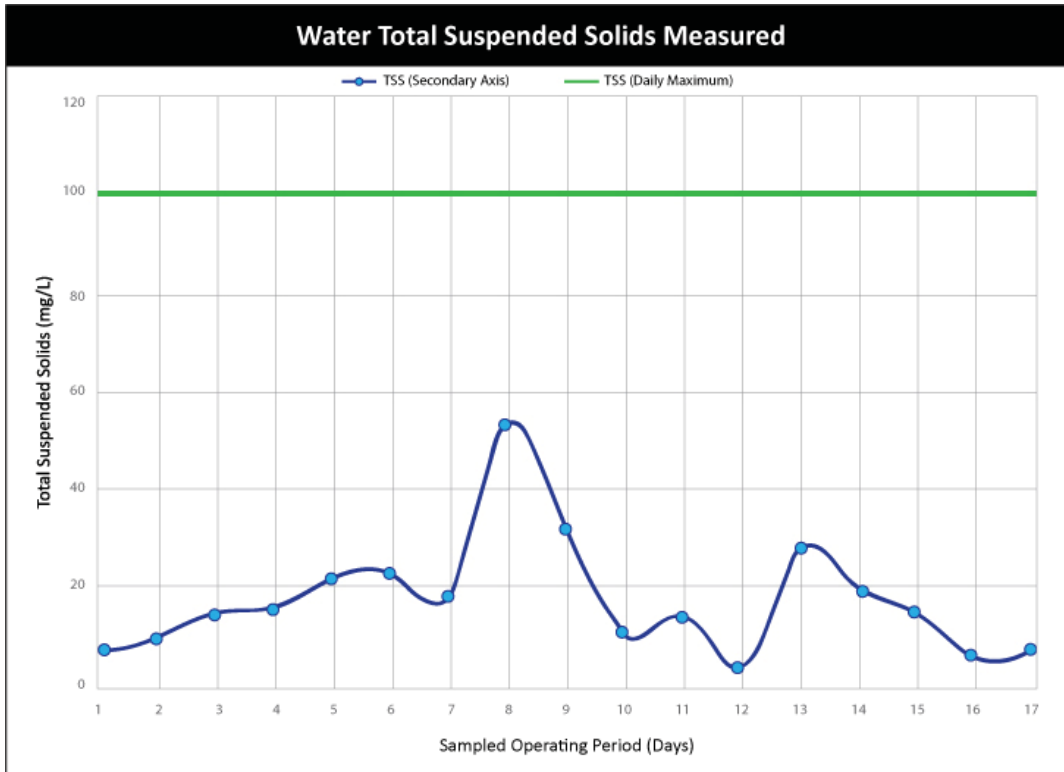


Figure 6: TSS graph

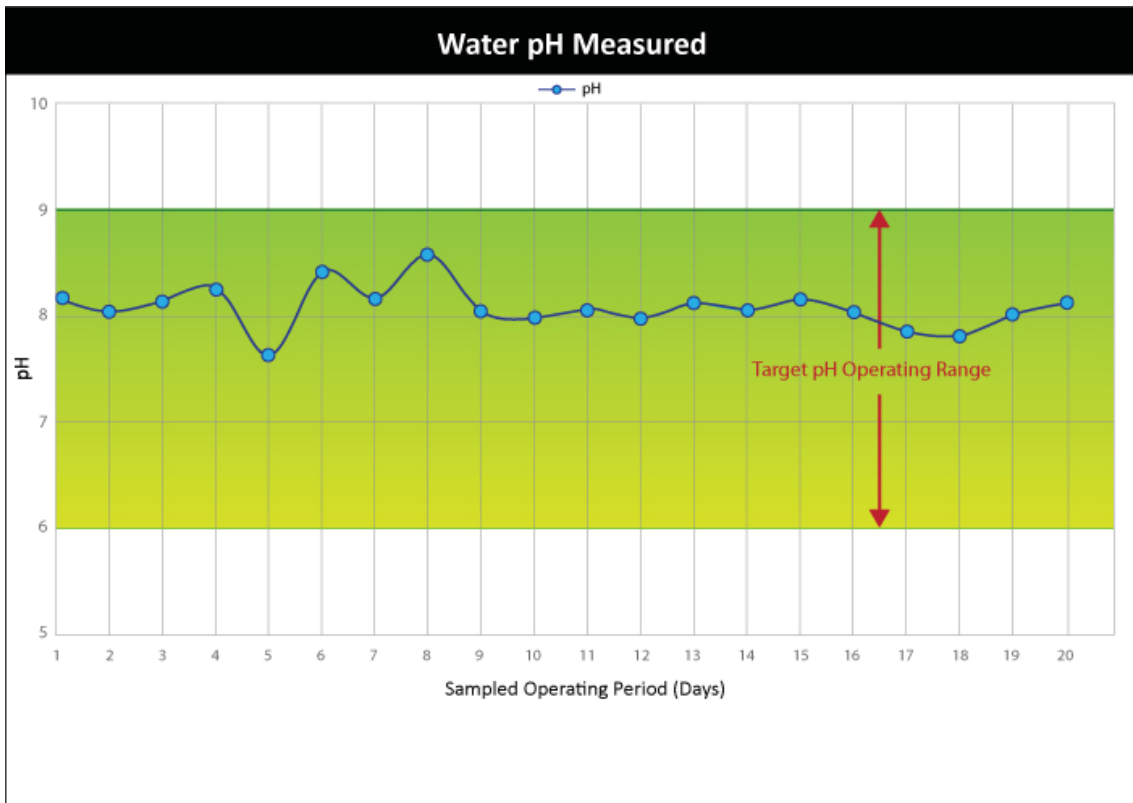


Figure 7: Water-pH graph

Constituent	Clarifier Inlet	Clarifier Outlet
As, µg/L	<6	<6
Se, µg/L	<9	<9
Hg, µg/L	<0.27	<0.27
Chloride, mg/L	14.7	5.34
Nitrate, mg/L	<0.5	<0.5
Nitrite, mg/L	<0.5	<0.5
Sulfate, mg/L	26.6	18.4
TDS, mg/L	146	110

**Figure 8: Clarifier inlet vs. outlet concentration**

In addition, the system has shown favorable performance on dissolved solids (TDS) concentrations, with the clarifier system showing no influence on inlet constituent levels, and in some cases reducing constituent levels (e.g., chlorides, sulfates; see Figure 8). As a once-through system, this performance was expected relative to minimizing the amount of time the bottom ash particulate and clarifier slurry remains in contact with the transport water. By design, the solids collected in the system are intended to remain in contact with water for no more than 24 hours, and typically less than 12 hours for most of the material, thereby reducing the risk of solids dissolution into the transport water. If the system is modified to operate as a full time closed-loop, zero liquid discharge system, the TDS levels would need to be moni-

tored on a consistent basis to confirm any potential risk of the cycling up of constituent concentrations.

**CONCLUSION**

With the successful implementation of the combined bottom ash dewatering and transport water clarifying system utilizing remotely located SFCs and clarifiers, this facility is a proven case study of state-of-the art technologies that can readily meet new and pending regulatory requirements while providing for expanded operating flexibility. In particular, the system has produced an effluent water quality that is suitable for discharge (under current permit requirements), can be readily recirculated in a closed-loop, zero liquid discharge system or be utilized for FGD makeup/process water.

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**Figure 9: Clarifier**

**BIOGRAPHY**



*Kevin McDonough is the Vice President of Global Sales & Marketing for United Conveyor Corporation. He received his Bachelor's and Master's Degrees from Montana Tech of the University of Montana in Environmental & Mining Engineering. Kevin has nearly 20 years of experience*

*in the air/water pollution control and power industries and has been highly active in the Coal Combustion Residual wet-to-dry conversion market for the better part of the past decade. Kevin has worked closely with utilities throughout the U.S. Coal Fleet to develop cost-effective solutions to meet regulatory compliance and operational needs.*

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WPCA Seminar  
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Ash Ponds**

***hosted by TVA  
September, 2019***



## Who We Are

The Worldwide Pollution Control Association (WPCA) has assembled a group of people and companies who are experts at some aspect of pollution control. In addition, the WPCA has organized a user advisory board who can give this group direction and assistance in performing service to pollution control business throughout the world.

## Our Mission

The mission of the WPCA is to enhance technical communication through seminars, technical journals and a website. The WPCA is a non-profit organization and our members and advisors need to be motivated by a desire to see the pollution control community make world wide technical progress through improved technical communication.

## Who Directs the WPCA?

The WPCA is a partnership which includes system/equipment/services suppliers, consultants and users. The WPCA President, Vice President and Advisory Committee are equipment users. The Corporate Sponsors and Board of Directors are suppliers. Together they develop annual seminars and events to achieve their goal of better technical communication for users of air pollution control systems.

## How do I become a Member of the WPCA?

In order to be a WPCA member, you must be an end user of pollution control equipment. When you register on-line for any WPCA sponsored seminar, you automatically become a member. If you would like to join, but cannot attend a seminar at this time, please download and send in the Registration Form at the top of the members list at [www.wpca.info](http://www.wpca.info). You will then be emailed regarding upcoming events and sent future copies of the WPCA News.

## Reducing Minimum Load Operation for the SCR and Improving System Reliability

*Written by Suzette Puski, Babcock Power*

Several utilities are being challenged to operate their SCR systems at lower loads to balance renewables. Babcock Power Environmental Inc (BPE), a Babcock Power Inc company, has been providing options to retrofit the SCRs to reduce Operating & Maintenance, increase system reliability and reduce minimum load limits.

BPE is currently working with the owner of two 900 MW coal-fired boilers to upgrade the ammonia injection and mixing systems of their existing SCR's. The existing ammonia systems are designed for 29% by weight aqueous ammonia and include the following equipment for each unit:

- Two storage tanks
- One, 100% capacity forwarding pump
- Two, 50% capacity dilution air fans
- One steam coil air heater
- Two SCR reactors
- Two vaporizers, one for each reactor
- Two ammonia flow control trains, one for each reactor
- Two steam-atomized ammonia nozzles, one per vaporizer
- A static mixer grid in each reactor inlet duct
- Two distribution manifolds, one for each reactor
- 28 injection lines per manifold, each line with a flow meter and manual balancing (tuning) valve.
- An ammonia injection grid (AIG) with four, 2-nozzle lances per injection line (224 nozzles per reactor)

The plant reports several ongoing maintenance issues. They typically find 20-40% of the ammonia nozzles plugged during inspections. The pressure drop over the air heater is also high, likely due to scaling caused by ammonia slip and SO<sub>3</sub>.

Plugging is a common problem with AIG's that have a large number of injection points. The nozzles have to be relatively small in order to maintain sufficient velocity to clear the nozzle. In addition, when multiple injection nozzles are located on a single lance, or multiple lances are served by a common

header, poor flow distribution in the piping and lances can lead to low flow in some nozzles, allowing ash and flue gas to enter. With extensive plugging of the AIG, the ammonia distribution cannot remain balanced. No mixer is likely to overcome gross maldistribution caused by plugged areas in the AIG.

### REDUCING THE NOZZLE COUNT

BPE will install a complete Delta Wing static gas mixing system designed to reduce load-dependent and firing-dependent NOx variation across the duct, and to rapidly mix ammonia injected across a fewer number of injection points. The mixing system design is in progress, but we anticipate using only 6 to 8 lances per reactor, each with a flow meter and balancing valve, replacing the existing 28 balancing valves per reactor. Each lance uses a single injection point rather than multiple nozzles per lance, providing direct control of each injection stream. This reduces the nozzle count from 224 nozzles to 6-8 nozzles per reactor.

Using the existing vaporizer and dilution air system, the lances would be 10-12" diameter, plain-end pipe located proximate to the static mixer plates. Plugging would be immediately identifiable since the flow rate to each lance is monitored, however, our experience indicates plugging does not occur with this design.

### IMPROVE FLUE GAS DISTRIBUTION

The new static mixing system is expected to have little or no net increase in pressure loss compared to the existing mixing elements and complex AIG that will be removed. Improving the ammonia to NOx distribution will eliminate scaling issues in the downstream air heater, reducing the overall system pressure drop. Reducing scaling across the air heater will eliminate forced outages and reduce soot blowing requirements, improving air heater basket life. Catalyst life is typically limited by increasing ammonia slip at the required rate of NOx removal, so improved distribution will increase the effective catalyst life. Improved mixing will also increase catalyst life by reducing ammonium bisulfate formation and the resulting fouling of catalyst pores.

The mixers will also improve the flue gas temperature distribution to the catalyst. Reducing the flue gas temperature deviation at the catalyst will reduce the catalyst minimum operating temperature.

**IN-DUCT VAPORIZATION FOR ENERGY SAVINGS**

The existing system uses cold reheat steam to heat dilution air and vaporize the aqueous ammonia. BPE uses air-atomizing nozzles to inject aqueous ammonia directly into the flue gas stream, eliminating the dilution air blower and steam consumption. A small stream of heated air is used to keep the nozzles clear of ash. In this system, a single-nozzle lance replaces each dilution air pipe, maintaining the low nozzle count and individual control of each injection stream.

In the current project, the total electrical power for the atomizing air compressor, protection air blower and heater is about one-half the power required for the existing dilution air blower. The existing steam consumption of about 10,000 lb/hr per unit is eliminated. Figure 10 shows the estimated steam and power costs for the two systems.

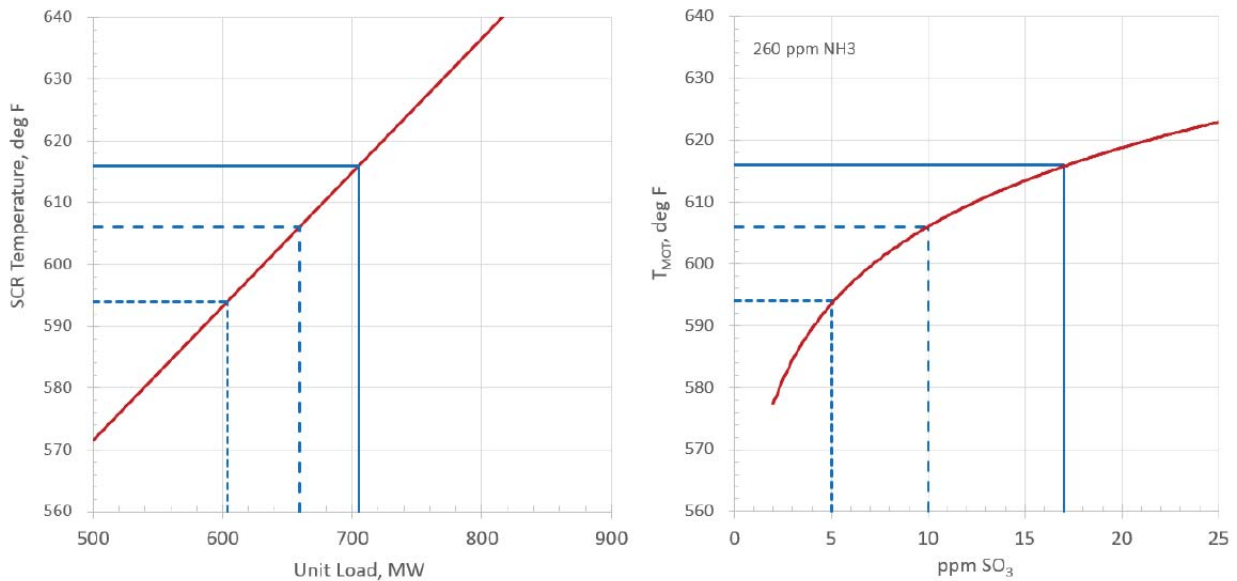
The energy for vaporization comes from the flue gas, but at a net savings relative to the existing system; the large dilution air stream reduces the flue gas temperature by about 6°F compared to 3°F for direct vaporization in the duct, so the air heater will recover more energy with direct vaporization. ID fan power will be reduced without the added burden of the dilution air, which currently represents about 1% of the flue gas flow. The small increase in temperature also allows for lower load operation with the SCR.

**FUTURE DSI**

The plant uses dry sorbent injection down stream of the air heater to manage SO<sub>3</sub> emissions from the wet scrubber. The SCR mixing system will be designed with specific mixers for future relocation of the sorbent injection upstream of the SCR reactor. Anticipated benefits include reduced sorbent consumption, reduced SO<sub>3</sub> emissions, and control of SO<sub>3</sub> entering the reactor, allowing the SCR to operate at lower temperatures. Currently the unit minimum load is limited by the catalyst Minimum Operating Temperature (MOT) for ammonia injection. The MOT is established by the cat-

	Existing Vaporizer/Dilution Air	New Direct Injection
Steam consumption, lb/hr		
Dilution air heater	9,340	0
Atomizing nozzle	980	0
Total steam	10,320	0
Power consumption, kW		
Dilution air fan	134	0
Atomizing air compressor	0	50
Protection air fan	0	2
Protection air heater	0	20
Total power	134	72
Evaluated cost, steam (\$2/MBtu, 70% capacity factor)	\$103,000	0
Evaluated cost, power (\$0.05/kWh, 70% capacity factor)	\$41,000	\$22,000
<u>Annual Power and Steam Cost (per unit)</u>	\$144,000	\$22,000

*Figure 10: Cost savings for direct injection of aqueous ammonia*



**Figure 11: Temperature vs. load (left), and catalyst Minimum Operating Temperature vs. inlet SO<sub>3</sub> (right)**

alyst supplier to avoid ammonium bisulfate (ABS) deposition. The MOT decreases with decreasing SO<sub>3</sub> concentration in the flue gas.

In Figure 11, the right-hand chart shows the reduction in MOT of the catalyst vs. the SO<sub>3</sub> concentration in the flue gas. The temperature at the SCR varies with plant load, as shown in the left-hand chart. The plant is currently limited to about 700 MW by the minimum catalyst operating temperature with a reactor inlet of 17 ppm SO<sub>3</sub>. Shifting DSI to the SCR inlet is expected to reduce the SO<sub>3</sub> to 10 ppm or less, and potentially to 5 ppm or less with effective mixing. With reduction to 10 or 5 ppm SO<sub>3</sub> ahead of the catalyst, the load range is expected to increase by 40-100 MW, to as low as 600 MW from the current limit of 700 MW. With or without sorbent, the mixing system will reduce the variation of temperature and composition across the catalyst face, increasing the load range by eliminating low-temperature or high-concentration zones that would require operating at a higher average temperature to avoid catalyst and air heater fouling.

Engineering evaluations help the customer understand the benefits that can be achieved with an aftermarket upgrade. An economic analysis can then be completed to justify what modifications will provide the most benefit to the customer

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**BIOGRAPHY**

*Suzette Puski started working in the power industry in 1991 after graduating in chemical engineering from Purdue University. She evaluated AQCS proposals, attended plant start-ups and completed optimization testing. She then transferred to R&D in manufacturing where she worked as a process engineer scaling up product from R&D to pilot-scale to the manufacturing plant. Over the last 12 years Suzette has worked for Babcock Power starting as a process engineer completing engineering, commissioning and startups, and optimization of AQCS systems. She now works in proposals where she uses her plant experience to provide practical solutions to the power industry*



# HRSG Ammonia Injection Optimization

*Written by Matt Gentry, Airflow Sciences Corporation*



**Figure 12: HRSG Plant in Western U.S.**

Gas turbine engines used for power generation often have a Heat Recovery Steam Generator (HRSG) to increase efficiency. The hot turbine exhaust is used to create steam in heat exchanger tube banks, which is then used to create additional electricity. The emissions control system to clean the gas turbine exhaust consists of both carbon monoxide (CO) and nitrous oxide (NO<sub>x</sub>) reduction through catalyst elements. The CO is reduced by a dedicated CO catalyst. The NO<sub>x</sub> reduction, via Selective Catalytic Reduction (SCR), requires that ammonia be injected upstream of the catalyst and thoroughly mixed with the turbine exhaust gases. The catalytic reaction of ammonia and NO<sub>x</sub> converts the NO<sub>x</sub> to nitrogen (N<sub>2</sub>) and water vapor (H<sub>2</sub>O) which then exhausts out the plant stack.

To optimize the performance of these catalytic reactions, and thus minimize plant emissions, there are several key design criteria related to the flow characteristics of the HRSG. In particular, after the exhaust gas exits the turbine, it must be carefully controlled such that:

1. Velocity distribution is uniform through the catalysts within 15%
2. Temperature profile is within +/-20° through the catalysts
3. Correct stoichiometric ratio of ammonia to NO<sub>x</sub> is provided through the SCR
4. Pressure drop is minimized

All these factors play a role in the resulting emissions, with the goal of minimizing CO and NO<sub>x</sub> emitted from the plant. This must be achieved while injecting the minimal amount of ammonia to avoid discharge out the stack (also called “ammonia slip”).

## HRSG PERFORMANCE IMPROVEMENT PROJECT

A western U.S. plant (Figure 12) with two HRSG units that handle the exhaust from 501F turbines was having issues with ammonia distribution and NO<sub>x</sub> catalyst performance. A redesign and installation of a new ammonia injection grid (AIG) was required to improve the situation. Concord Environmental of Vorhees, New Jersey performed the engineering, procurement, and construction of the AIG, as well as installation of a new catalyst. Airflow Sciences Corporation of Livonia, Michigan performed the flow system design optimization. This involved conducting a computational fluid dynamics (CFD) flow study to analyze the current system and recommend design changes to the HRSG and AIG. The goal of the flow modeling was to determine inefficiencies with the current system and develop a new design to meet the goals of optimizing the ammonia, velocity, and temperature distribution through the SCR catalyst while minimizing pressure loss.

The geometry of the HRSG is shown in Figure 13 on page 12. Flow exits that gas turbine and passes through 2 tube banks (red), the duct burner (gray), and 4 more tube banks before encountering the CO catalyst (yellow). The ammonia is injected through the AIG and combined flow passes through the SCR catalyst (blue) and additional tube banks before exiting the stack.

The flow modeling was performed using the Azore® CFD program for Azore Software LLC. This is a 3D polyhedral CFD tool that includes flow and heat transfer simulation. The heat addition from the duct burners and the heat removal from the tube banks was included in the simulation.

## BASELINE CFD RESULTS

The baseline CFD results at full unit load confirm poor ammonia distribution at the SCR catalyst face. Figures 14 and 15 on page 13 show the overall flow patterns through the

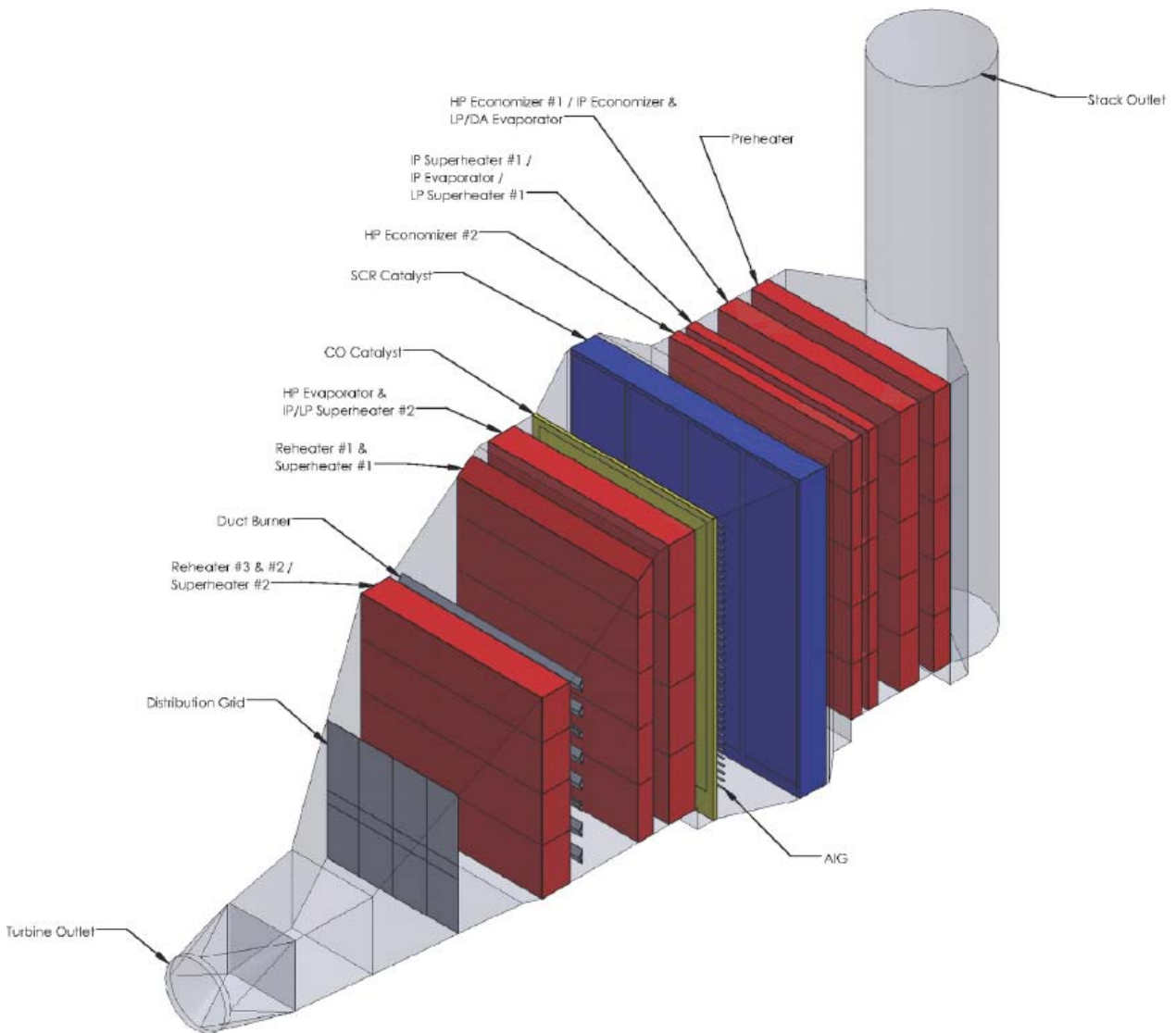
full HRSG. Figure 14 on page 13 provides flow streamlines colored by the gas velocity. This indicates that flow exits the turbine at very high velocity, on the order of 300 ft/s (90 m/s), and then decelerates as the cross sectional area increases. The flow velocity through the tube banks and catalysts is on the order of 15 ft/s (4.5 m/s) and is well behaved.

Figure 15 on page 13 shows a side view of the HRSG with velocity contours indicating magnitude and velocity arrows/vectors indicating directionality. Figure 15 has a different color scale than Figure 14 and thus shows the velocities through the tubes and catalysts more clearly.

Figure 16 on page 14 is a close up view of the region starting at the AIG, and depicts the ammonia concentration in

several planes downstream of the AIG. Figure 17 on page 14 is a plan view of the HRSG from the CO catalyst to the stack inlet. Note the high levels of ammonia concentration near the walls of the unit. A fair amount of ammonia does not get mixed into the flow stream, but continues to be trapped near the walls, as the gases flow toward the stack inlet. The large red areas would correspond to areas of high ammonia slip. The CFD results indicate that non-uniform flow near the AIG is causing the ammonia to be concentrated in recirculation zones, due mainly to an expansion in the cross-sectional area of the HRSG ductwork in the region of the AIG.

The typical AIG consists of an arrangement of pipes that feed vaporized ammonia. A single feed pipe from the vaporizer splits to a number of headers, each of which feeds



**Figure 13: Geometry of HRSG from turbine outlet to stack showing internal tube banks, catalysts, and AIG.**

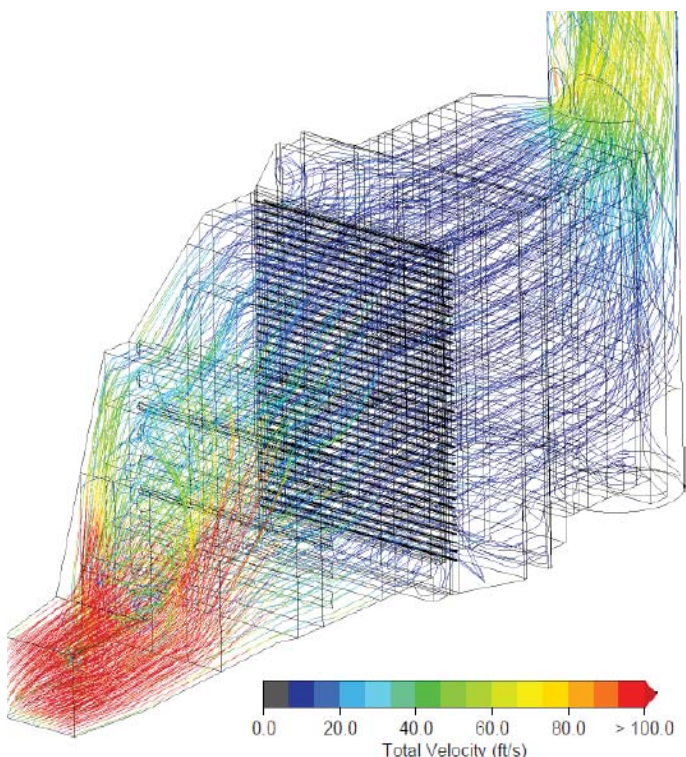


Figure 14: Baseline CFD results represented as flow streamlines.

a number of AIG lances. The lances are arranged over the cross section of the HRSG to provide uniform coverage of injected ammonia. Each lance has a large number of nozzles through which the ammonia is injected into the flow stream.

In this case, there were 9 headers feeding 36 lances, on either side of the duct. Each lance had 16 nozzles, for a total of 1,024 ammonia injection points over the HRSG cross section. When designing an AIG, common practice is to carefully consider the diameter sizes for the header and lance piping, along with the nozzle size, as well as the layout and number of lances and nozzles. These design factors are critical to achieve balanced flow from the thousands of nozzles in order to obtain sufficient mixing and a uniform ammonia distribution at the SCR catalyst.

**DETAILED AIG MODELING**

In modeling an HRSG, it is not correct to simply assume that equal flow exits each nozzle of the AIG. Airflow Sciences’ technique is to create a second detailed CFD model of the AIG itself to simulate the internal flows and quantify the flow split between nozzles. Figure 18 on page 15 shows an example of AIG geometry and the velocity of vaporized ammonia within the header and lances. Figure 19 on page

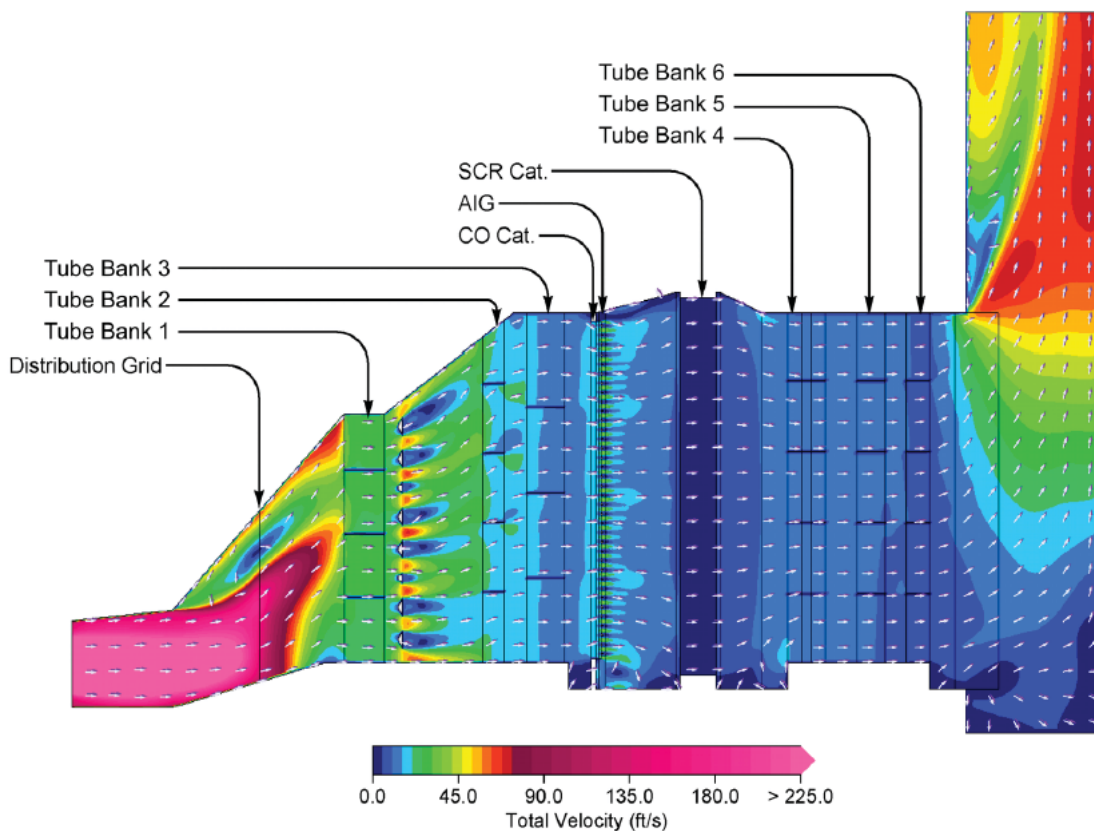
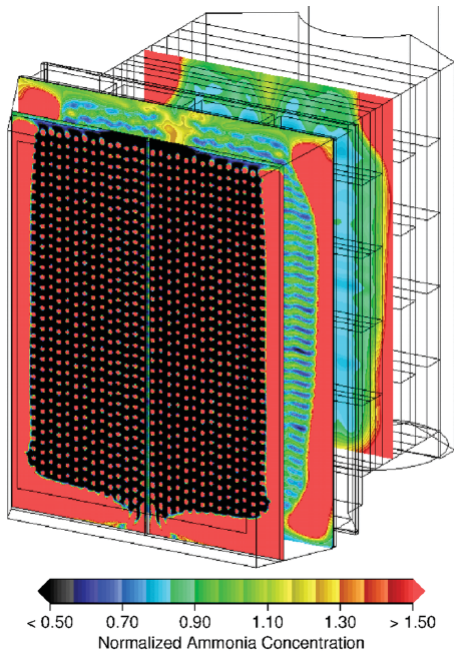


Figure 15: Baseline CFD results, side view, indicate how the gas velocities change through the HRSG.

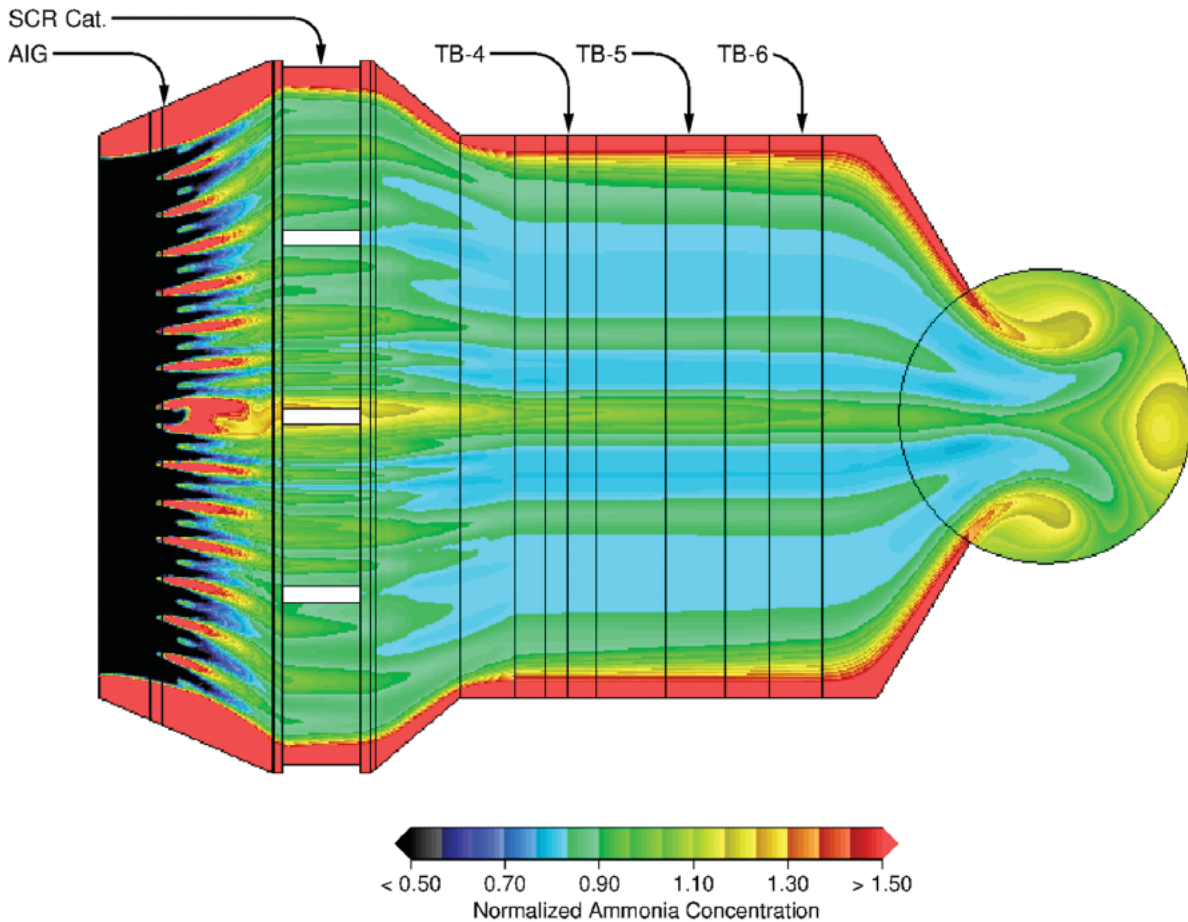


**Figure 16: Baseline ammonia concentration, with areas in red being undesirable.**

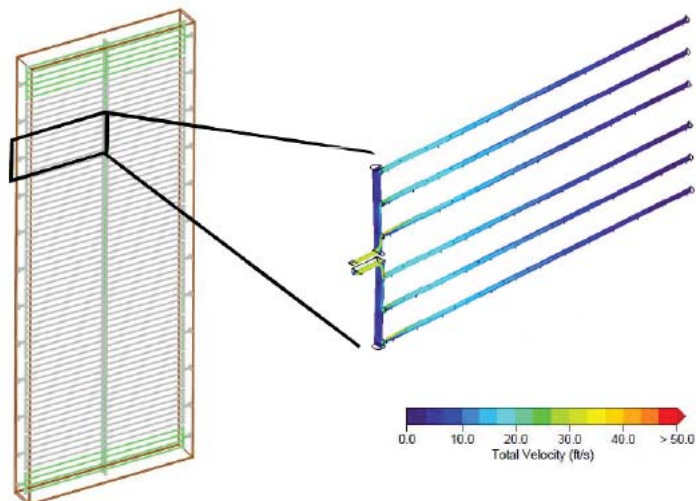
15 is a closeup of the nozzle locations on the lances. One of the benefits of this detailed model is an ability to analyze the amount of heat transfer from the gas flowing past the lances to the ammonia within the lances. This abrupt increase in temperature results in a density change for the ammonia mixture, affecting the pressure and velocity within the lances. All of these factors were considered for the redesign of the AIG, including a change to the spacing of the lances and nozzles. The general goal of ammonia injection is for the amount from each nozzle to be within 2% of other nozzles to ensure uniform distribution.

**CFD DESIGN OPTIMIZATION**

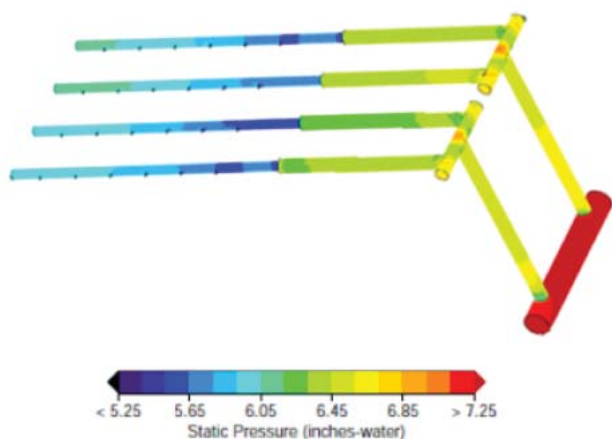
The detailed AIG model data was used for more accurate representation of ammonia injection in the full HRSG ductwork CFD model. The non-uniform flow concerns near the AIG that were discovered in the baseline analysis were corrected with the addition of flow control baffles to redirect flow inward, resulting in an elimination of recirculation zones and a reduction in AIG bypass. In addition, the AIG was redesigned including a local static mixer to improve ammonia distribution at the SCR. The mixer had very low pressure



**Figure 17: Plan view of baseline ammonia concentration, showing excess ammonia along the walls and entering the stack, i.e. ammonia slip.**



**Figure 18: Ammonia velocity through a typical header and lances, with the data used as input for the full HRSG CFD model.**



**Figure 19: Pressure profile in header and lances, with sufficient pressure being required to eject the ammonia from the furthest nozzle.**

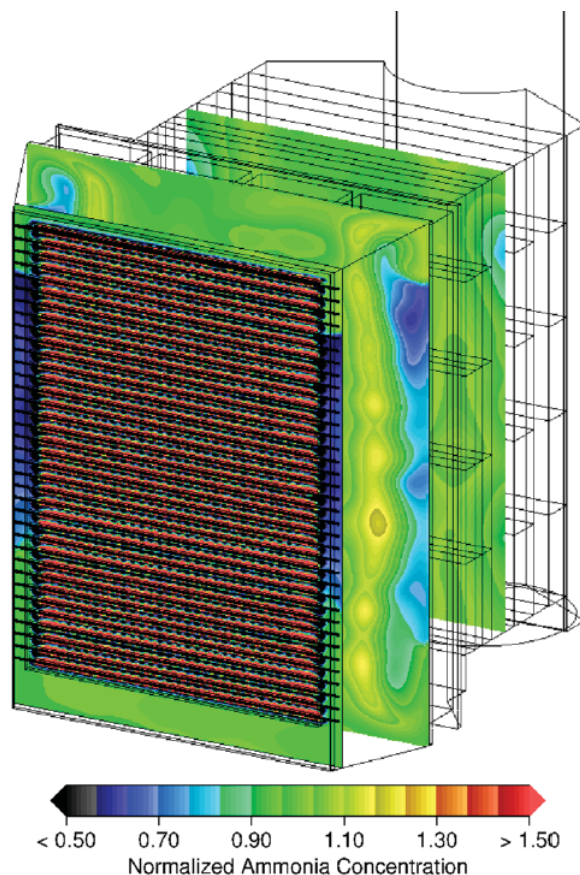
loss (~0.1 inch H<sub>2</sub>O / 25 Pa). The CFD model was run on the final design; Figures 20 on page 15 and 21 on page 16 show the ammonia concentration results for the same views as the baseline Figures 16 and 17. Most notable is the absence of high ammonia concentrations near the walls. A comparison of the plan views shows more uniform distribution of the ammonia across the width of the HRSG. The amount of ammonia slip is significantly lower in this redesign.

An isometric view of the ammonia concentration for the new design geometry is depicted in Figures 22 and 23 on page 16 for comparison. In addition to the redesign of the AIG and the baffles at the edges to redirect flow, the position of the AIG was moved upstream. This new placement allowed for more residence time for mixing prior to the SCR catalyst

and prevented ammonia from flowing upstream. The baseline ammonia RMS of 69% at the SCR catalyst face was reduced to 7% RMS with the redesign, indicating a significant improvement in uniformity.

**PLANT RESULTS**

The CFD modeling conducted by Airflow Sciences successfully solved the poor ammonia distribution issue in the HRSG. The recommended AIG and flow control devices were installed by Concord Environmental in late 2017. The unit has operated well since coming back online. Plant operating experience has confirmed that since the installation of the redesigned AIG, NO<sub>x</sub> control has improved and that ammonia usage has decreased 15-25% depending on load and other conditions. In addition, ammonia salt formation had dropped off significantly on the tube banks downstream of the SCR catalyst. This was evident during a recent outage when less debris needed to be cleaned from the tubes compared to previous operating experience. The plant representative stated that the AIG redesign “appears to be a great success”.



**Figure 20: Redesigned ammonia concentration, showing elimination of AIG bypass.**

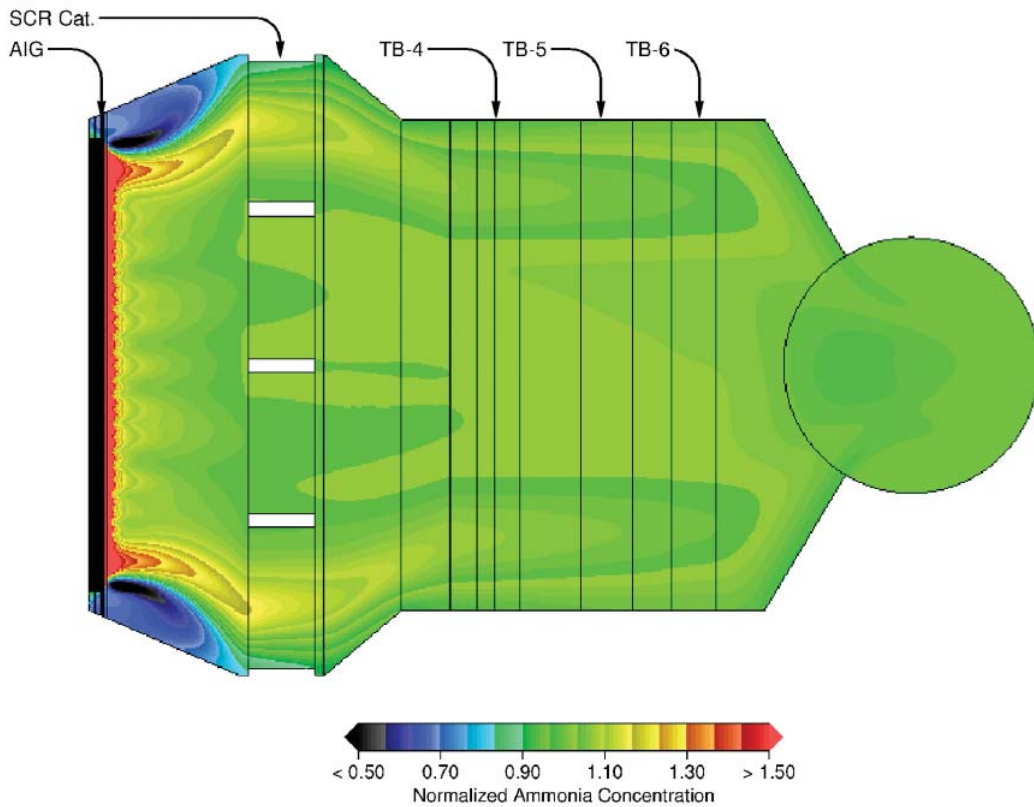


Figure 21: Plan view of redesigned ammonia concentration, showing more uniform distribution.

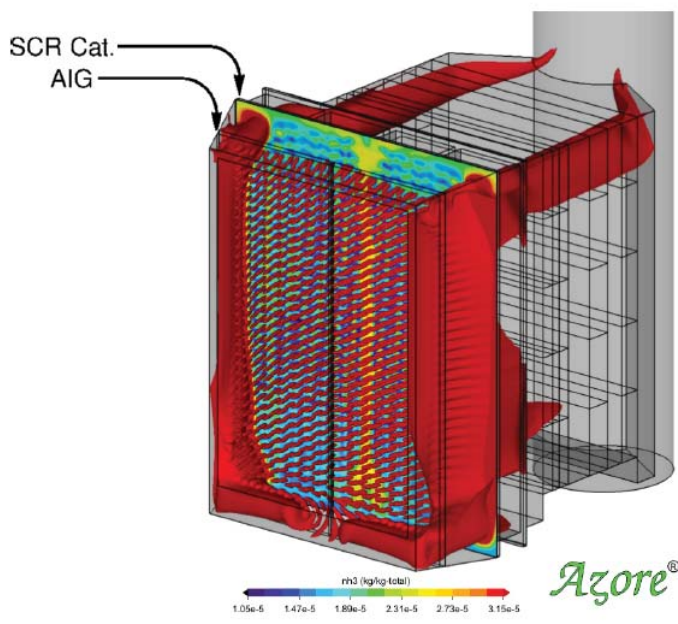


Figure 22: Baseline ammonia concentration, showing AIG bypass at the injection locations as well as along the edges.

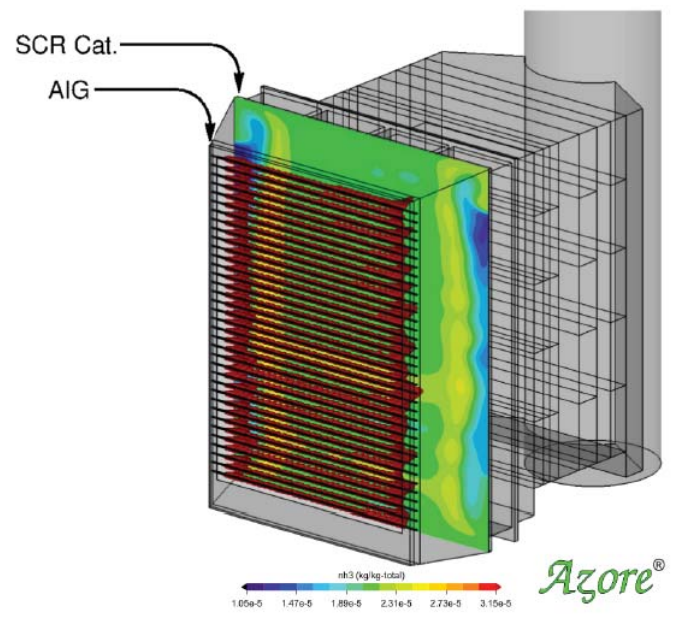


Figure 23: Redesigned ammonia concentration, indicating improved ammonia flow into the gas stream and uniform profile at the SCR catalyst.

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**BIOGRAPHY**



**Matthew R Gentry received his M.S.E. in Aerospace Engineering from the University of Michigan in 2004, with a specialization in structural mechanics. He has worked for ASC for over 13 years, performing flow modeling as well as both laboratory and field testing. He has served as project manager for HRSG, SCR, and sorbent injection projects, helping to optimize pollution control performance in industrial applications.**

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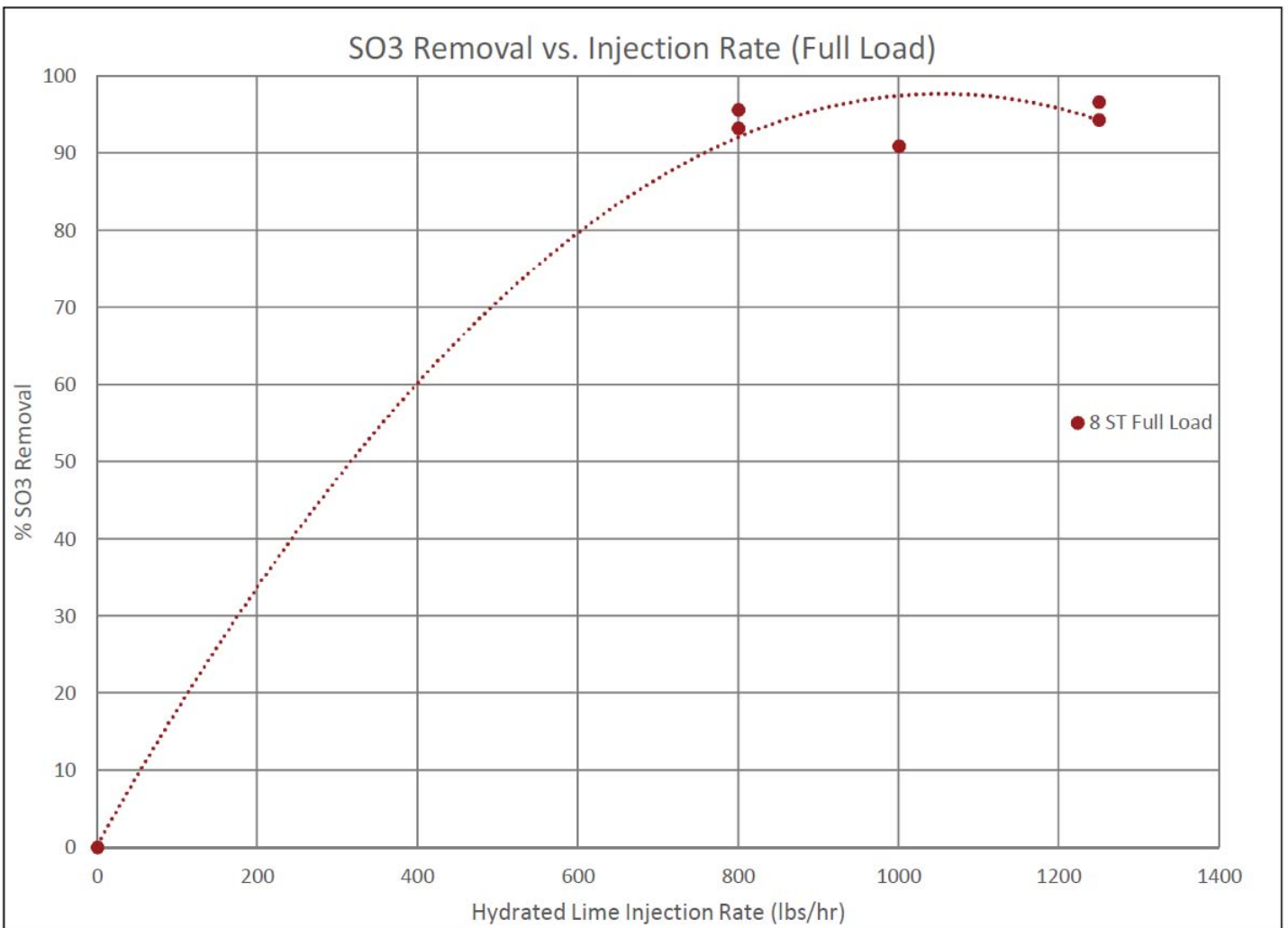


## Dry Sorbent Injection: A Solution to SCR MOT

*Written by Dylan Hardy and Grace Whiteford, Nol-Tec Systems*

In the current economic climate, coal fired power plants are striving for total plant optimization to remain competitive. This includes looking for new creative ways to optimize performance and lower operating costs. Currently, the market is demanding coal fired power plants to increase their operating flexibility which translates to the need for lower baseload, more cycling, and improved efficiency. This additional turn down requirement has a key obstacle that needs to be overcome before making lower turndowns possible: minimum operating temperature (MOT). This plays an integral role in SCR (selective catalytic reactor) operation which is a limiting factor in boiler turndown.

The SCR operates with an ammonia injection grid upstream of a catalyst to remove NOx. Ammonia injection is integral in NOx removal, but must be kept in check due to adverse effects downstream if over injection occurs. During over injection, unreacted ammonia “slips” and adversely reacts with SOx pollutants forming unintended byproducts like ammonium sulfate and ammonium bisulfate (ABS). At low temperatures, ABS condenses out of the flue gas, leading to reduced plant efficiency, unit curtailment and ultimately an outage for cleaning. The demand for plants to decrease their minimum operating load is rising, which leads to lower operating temperature demands.



*Figure 24: SO<sub>3</sub> Removal Results with injection occurring at the SCR inlet. Eight lance-less Sorb-Tec units were installed on the duct with the unit operating at full load.*



*Figure 25: Test set up at SCR inlet. Eight (8) Sorb-Tec units were installed to maximize dispersion of the sorbent.*

SCRs generally operate with a minimum temperature requirement due to the potential for ABS formation. This limits the loads at which plants can operate, creating one of two problems: utilities cannot meet the low load demands or cannot meet the NO<sub>x</sub> mitigation requirements because ammonia injection needs to be shut off.

Dry sorbent injection is a process which dry chemicals, usually sodium or calcium based, are added to the flue gas stream to mitigate for acid gases (SO<sub>2</sub>, SO<sub>3</sub>, and halogens). Historically, dry sorbent injection has been located before or after the air heater to remove pollutants prior to exiting the stack. Most recently, it has been used to remove SO<sub>3</sub> ahead of the air heater in order to reduce acid dew point temperatures and decrease the risk of ABS fouling of the air heater.

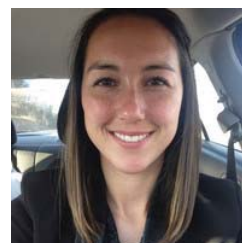
Now, DSI is being utilized as a means of removing SO<sub>3</sub> ahead of the SCR to help address MOT related issues. Removing SO<sub>3</sub> prior to the SCR greatly reduces the possibility of ABS formation allowing the SCR to operate at lower temperatures than previously imagined. Although it was believed that pre-SCR injection would plug off or blind the catalyst, to date, it has been found that there are no negative impacts to the SCR or air heater operation.

Nol-Tec has partnered with multiple utilities in testing this concept. In one example, field testing utilizing enhanced hydrated lime along with the addition of Nol-Tec's Sorb-Tec (ST) Lance-less Injection Technology achieved up to 97% SO<sub>3</sub> removal at the air

heater inlet location utilizing stack testing methods at full load (585MW). Full load represented worst case operating conditions due to higher levels of SO<sub>3</sub> generation occurring as well as higher gas volumes being present which reduces the amount of time available for the sorbent to find and react with the SO<sub>3</sub>.



*BIOGRAPHY*



Grace Whiteford is a product engineer at Nol-Tec Systems and has been with the company since 2015. During at Grace's tenure at Nol-Tec, she has held several other

positions including technical services, application engineering, international business development, and sales, with an focus on pollution mitigation. Her current responsibilities include coordinating mobile testing and with heavy involvement in all aspects of the environmental solutions division of Nol-Tec. Grace graduated from the University of Minnesota Duluth with a Bachelor of Science in Chemical Engineering.

Dylan Hardy works in the Business Development group as the Product



Manager of Environmental Solutions at Nol-Tec Systems. With a mechanical engineering background in bulk material handling and pneumatic conveying, Dylan started his career as a process design engineer and quickly began to manage the portable dry sorbent injection test systems. In 2019 he transitioned to his current role where he added the key responsibility of developing innovative solutions offered within the Power and Utility industries. He is focused on refining Nol-Tec's environmental solutions sector, and expanding our offerings to new and emerging markets. Dylan has a Bachelor of Science degree in Mechanical Engineering from the University of Minnesota and has been working at Nol-Tec Systems since May 2015.



*Figure 26: Elevation view of SCR inlet duct. Injection occurred at the location noted above.*

At this level of removal, the minimum operating temperature of the SCR was eliminated, allowing the plant to capitalize on more opportunities with their newfound operational flexibility. The plant moved forward with a permanent retrofit of their existing DSI system in 2018.

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## BOF ESP Enhancement

*Written by Mike Volker, Schenck Process*

### OVERVIEW

Schenck Process was approached by a steel mill in Illinois to provide an assessment of their Basic Oxygen Furnace (BOF) Electrostatic Precipitator (ESP). The goal was to increase the reliability of the unit and eliminate production delays due to required maintenance of the control device. This article will review the historical data as well as detail the improvements made to achieve the customer's goals.

### PLANT LAYOUT

The melt shop consists of two identical side-by-side BOFs, A&B in a typical arrangement, with a nominal heat size of 96.5 tons. Gases generated during the BOF charge and blow operations are collected in hoods above each furnace and routed to a damper house through separate, vertical ducts. Only one furnace is operated at a time. Gases from this furnace enter a compressed air-assisted water spray cooling chamber which serves to cool the gases and provides drop-out of large particulate. The cooled gases exit into a horizontal duct and are routed into two modified ESP boxes utilizing a common inlet manifold duct.

*Figure 27: Modifications and additional space required for ESPs*



### ELECTROSTATIC PRECIPITATOR – ORIGINAL DESIGN DETAILS

#### No. 3 - Joy Western ESP

The original Joy Western three chamber, three field ESP currently utilizes only one chamber. This chamber has recently been outfitted with new internals, and has 27 gas passages, 11 inch plate spacing, with rigid electrodes. Each field is nine feet long by 20 feet high encompassing 29,160 sq. ft. collecting surface area with an aspect ratio of 1.4.

There is one TR set per field, rated at 45kV, 500mA. This ESP has inlet perforated plates with a rapper on the perf plate. With 96,000 acfm and a velocity of 3.23 ft./sec, the treatment time is 8.35 seconds.

#### Nos. 4 & 5 – SEI ESP

The SEI two chamber ESP has three mechanical fields and six electrical fields. Each mechanical field has 15 gas passages and 12 inch plate spacing with rigid electrodes. Each field is 12 feet long by 32 feet high encompassing 69,120 sq. ft. of collecting surface with an aspect ratio of 1.1. Each mechanical field has one TR set rated at 70kV, 750mA with leading and trailing plate rappers for 3,072 sq. ft. surface area per rapper.

As can be seen in the picture, additional space and consequently additional support was required for two of the four new TR sets as there was not enough room on the ESP roof.

	Chamber 3	Chamber 4	Chamber 5	Total
ESP Design Specification	96,000 acfm	96,000 acfm	96,000 acfm	288,000 acfm
Spring 2012	73,604 acfm 245°F	94,600 acfm 245°F	94,633 acfm 245°F	262,870 acfm 245°F
Spring 2013	56,800 acfm 224°F	129,000 acfm 351°F	93,000 acfm 337°F	278,800 acfm 304°F
Spring 2014	64,489 acfm 251°F	82,900 acfm 251°F	82,914 acfm 251°F	230,318 acfm 251°F

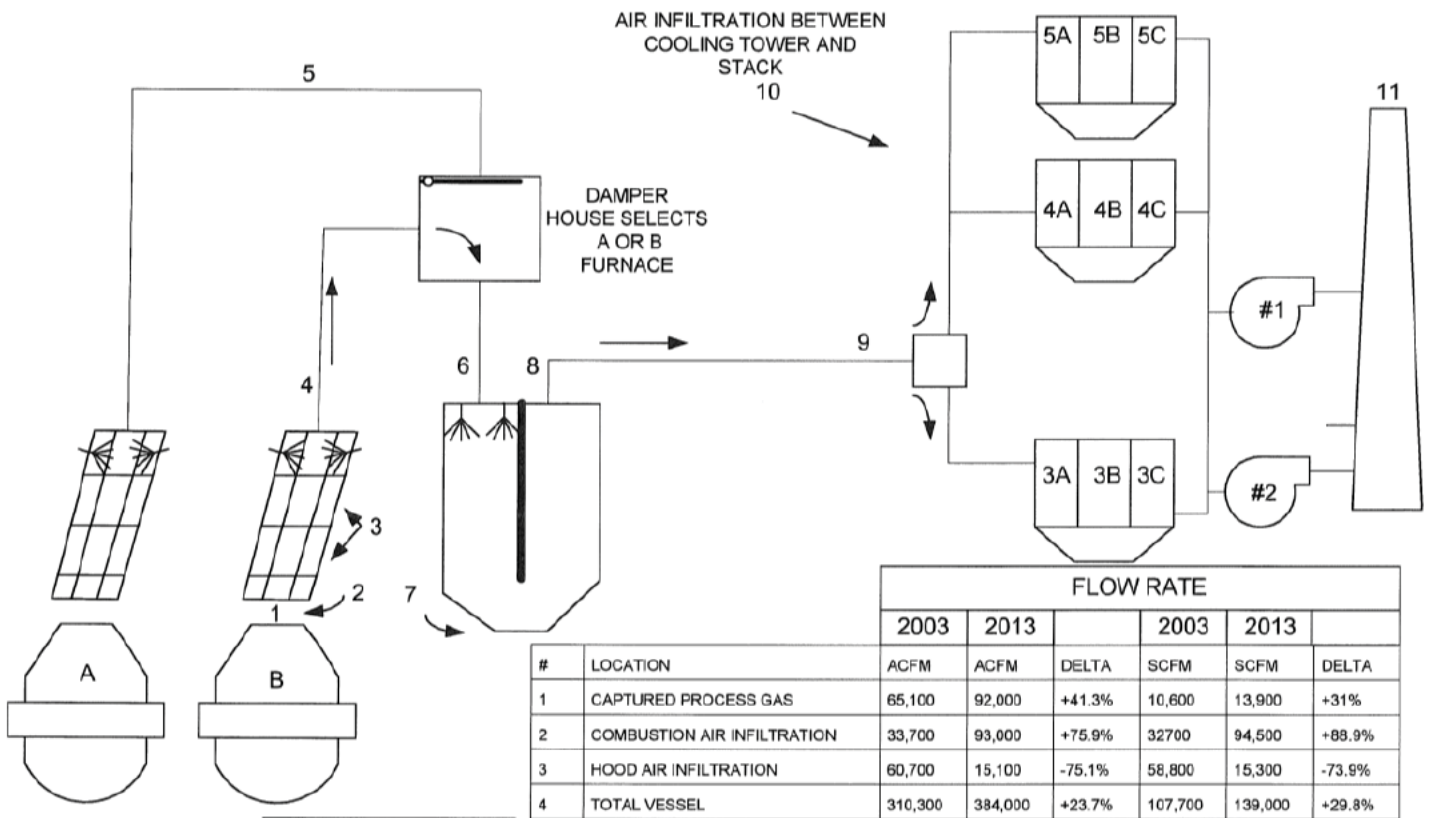


Figure 28: Data from various inspections

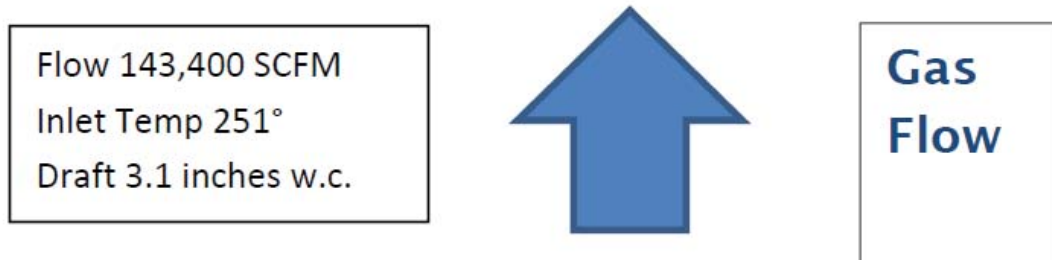
**HISTORICAL PROCESS ANALYSIS**

A detailed internal ESP inspection was performed to evaluate integrity and current performance of the three operating ESP chambers. Data from two separate evaluations was provided for historical analysis: May 2003, March 2013. Repairs were performed on the duct work and hoods during the spring 2013 outage, including replacing the chamber 3 inlet downcomer.

There is an internal connection between every two electrical sections. This ESP has an inlet and outlet perforated plate with a rapper on the inlet perf plate. With 96,000 acfm and a velocity of 3.23 ft./sec, the treatment time is 10.80 seconds.

**Operational Data before modifications - November 2016**

Chamber 5	Chamber 4	Chamber 3
<b>TR 5-C</b> 70kV, 750mA	<b>TR 4-C</b> 70kV, 750mA	<b>TR 3-C</b> 45kV, 500mA
0 SPM 173 AAC 257 VAC 730 mADC 44 kVDC 145° Firing Angle	0 SPM 173 AAC 244 VAC 756 mADC 43 kVDC 108° Firing Angle	0 SPM 65 AAC 400 VAC 490 mADC 39 kVDC 173° Firing Angle
<b>TR 5-B</b> 70kV, 750mA	<b>TR 4-B</b> 70kV, 750mA	<b>TR 3-B</b> 45kV, 750mA
0 SPM 156 AAC 253 VAC 756 mADC 45 kVDC 106° Firing Angle	0 SPM 173 AAC 275 VAC 730 mADC 47 kVDC 154° Firing Angle	0 SPM 43 AAC 267 VAC 210 mADC 39 kVDC 100° Firing Angle
<b>TR 5-A</b> 70kV, 750mA	<b>TR 4-A</b> 70kV, 750mA	<b>TR 3-A</b> 45kV, 750mA
0 SPM 173 AAC 257 VAC 730 mADC 44 kVDC 180° Firing Angle	0 SPM 102 AAC 328 VAC 530 mADC 57 kVDC 180° Firing Angle	26 SPM 165 AAC 396 VAC 428 mADC 44 kVDC 179° Firing Angle



*Figure 29: ESP layout showing AVC readings from 2016*

**PERFORMANCE**

As seen in the above ESP Layout showing AVC readings from 2016

- Chambers 4 and 5 are current limited and thus also kV limited.
- During the time this data was collected, Chamber 3, section B had a breaker problem and was being limited to prevent tripping. This was temporary and resolved, but affected the data.
- Sections A and C are kV limited (45 kV max) due to 11 inch plate spacing.

**MODIFICATIONS AND RESULTS**

Through data analysis and performance calculations, several recommendations were provided to the plant. The most cost effective solutions were looked at first and it was decided that this ESP would greatly benefit from additional power.

**Recommendations**

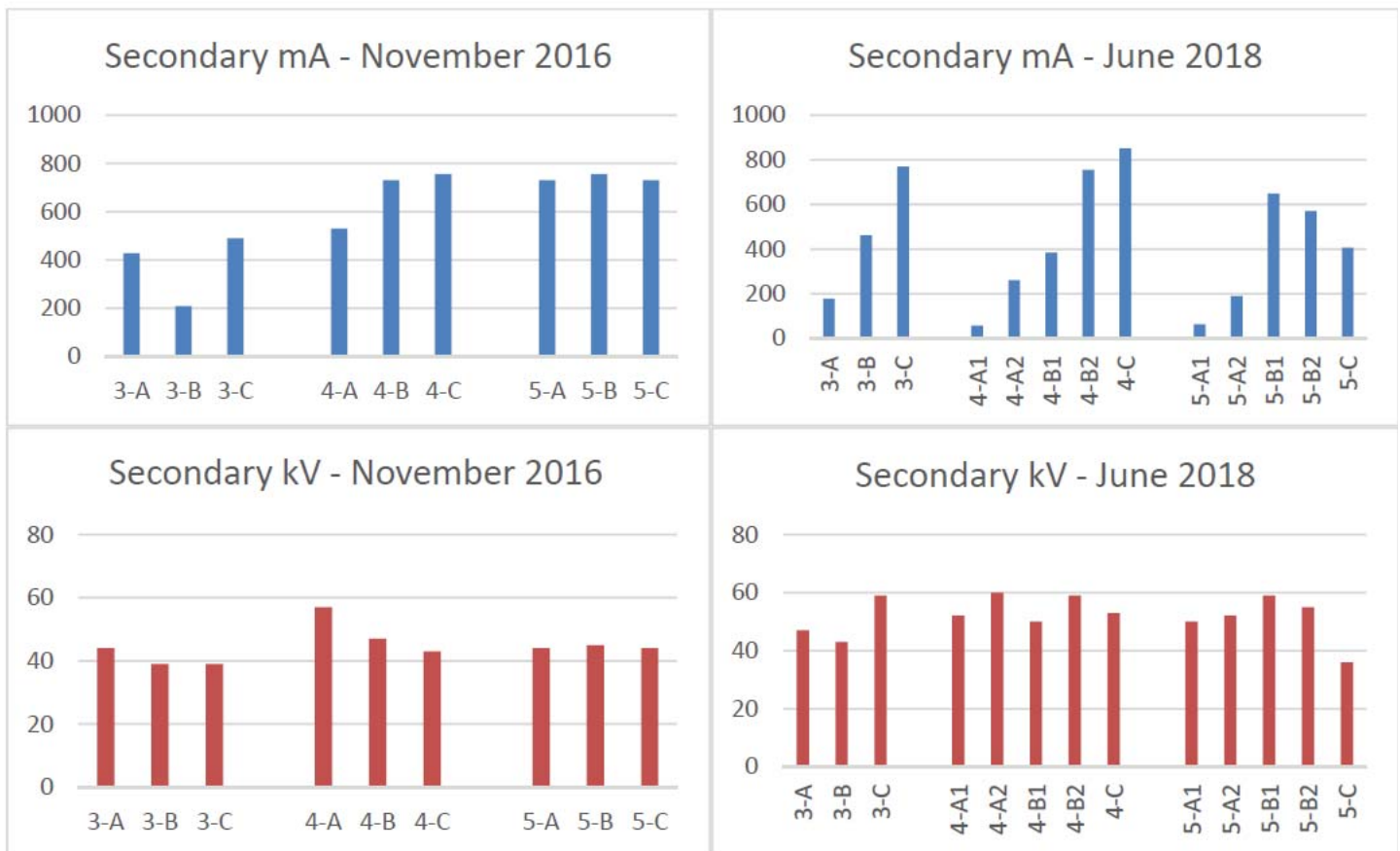
1. Sectionalize chambers 4 and 5 to increase the number of discrete electrical sections
2. Repower sections 4 & 5 with additional TR sets, sized appropriately for the plate spacing and electrode design
3. Increase the ESP power supply feed-through holes and replace the bushings allowing for the new higher kV power supplies.

In May 2017, the first two fields in chambers 4 and 5 were

sectionalized, and four additional, larger TR sets were purchased. The difficulty on this installation was placement of the additional TR sets since there was no room on the ESP roof for the new power supplies. Additional structure was added to the ESP, cantilevered off the back, as seen Figure 27 on page 21.

Four new control cabinets were purchased along with new, larger feed-through insulators on the roof, allowing for the higher kV rating of the TR sets. The flow was then balanced between all three chambers, slightly skewed to chambers 4 and 5 since there is additional surface area in these chambers which allows for more collection of particulate.

As can be seen in the two sets of data from before and after the modification and addition of power supplies and controls, the average kV from all three chambers has been in-



2016 Summary	
Total mA	Average kV
5,360	44.67

2018 Summary	
Total mA	Average kV
5,599	51.92

*Figure 30: Graph of T/R Operating Data, before and after the modifications.*

Operational Data after modifications - 2018

Chamber 5	Chamber 4	Chamber 3
<b>TR 5-C</b> <b>60 kV, 1,250 mA</b> 60 SPM 131 AAC 174 VAC 406 mA 36 kV 79° Firing Angle	<b>TR 4-C</b> <b>60 kV, 1,250 mA</b> 10 SPM 215 AAC 260 VAC 851 mA 53 kV 130° Firing Angle	<b>TR 3-C</b> <b>45kV, 500mA</b> 0 SPM 148 AAC 353 VAC 770 mA 59 kV 150° Firing Angle
<b>TR 5-B2</b> <b>70 kV, 750 mA</b> 0 SPM 138 AAC 326 VAC 570 mA 55 kV 160° Firing Angle	<b>TR 4-B2</b> <b>70 kV, 750 mA</b> 0 SPM 173 AAC 358 VAC 755 mA 59 kV 141° Firing Angle	61 SPM 90 AAC 274 VAC 462 mA 43 kV 97° Firing Angle
<b>TR 5-B1</b> <b>70 kV, 750 mA</b> 4 SPM 137 AAC 354 VAC 649 mA 59 kV 129° Firing Angle	<b>TR 4-B1</b> <b>70 kV, 750 mA</b> 10 SPM 85 AAC 296 VAC 385 mA 50 kV 122° Firing Angle	
<b>TR 5-A2</b> <b>60 kV, 400 mA</b> 43 SPM 44 AAC 303 VAC 190 mA 52 kV 99° Firing Angle	<b>TR 4-A2</b> <b>60 kV, 400 mA</b> 1 SPM 56 AAC 346 VAC 261 mA 60 kV 130° Firing Angle	
<b>TR 5-A1</b> <b>70 kV, 750 mA</b> 75 SPM 15 AAC 206 VAC 64 mA 50 kV 59° Firing Angle	<b>TR 4-A1</b> <b>70 kV, 750 mA</b> 75 SPM 13 AAC 204 VAC 58 mA 52 kV 33° Firing Angle	59 SPM 41 AAC 257 VAC 178 mA 47 kV 96° Firing Angle



Figure 31: Operational data after modifications - 2018

creased by more than 7 kV. The total secondary mA is not much higher than prior to the modifications, but higher kV is a more important factor in ESP performance.

With the modifications made to the chambers 4 & 5, the plant is now able to split the flow evenly through all three chambers. Collection in the overall ESP has increased since the modifications were completed. Our customer provided the following conclusions:

The sectionalization and additional power supplies allow the ESP to maintain a balanced and even collection level. This has proven its value when a section is having an issue. The sectionalization and additional power allow us to keep running until we can find a window to make any needed repairs. "We are also seeing better collection with the finer fluxes that we have been getting"

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### **BIOGRAPHY**

*Mike Volker, Product Specialist, Environmental Controls, Schenck Process. Over 29 years' experience with electrostatic precipitators, power supplies, control operation, optimization and process optimization and troubleshooting.*



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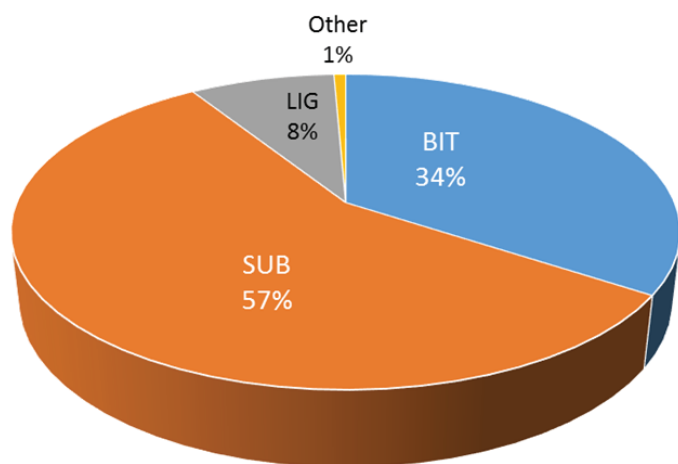
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## OVERVIEW OF MERCURY CONTROL APPROACHES USED BY U.S. PLANTS

*Written by Sharon Sjostrom, ADA-ES, Inc and Connie Senior, formerly with ADA-ES, Inc*



**Figure 32: Distribution of coal fired for power generation in US, Sept 17–Aug 18<sup>1</sup>**

### INTRODUCTION

Development and implementation of mercury controls for coal-fired power plants in the US has a relatively long history. Pilot testing at operating power plants to determine the effectiveness of activated carbon injection to limit mercury emissions began in the early 1990s. Hundreds of full-scale demonstrations of mercury control technologies have taken place since DOE began providing funding in 2001. On December 16, 2011, the EPA issued the final Mercury and Air Toxics Standards (MATS) rule, which took effect on April 16, 2012. Almost all affected units had to be in compliance by April 16, 2016. Most units now have at least two years of experience managing plant operations to meet compliance limits.

As part of the Mercury and Air Toxics Standard (MATS), affected coal-fired power plants must report their hourly mercury emissions to the U.S. Environmental Protection Agency (EPA). Plants employ a variety of strategies to reduce mercury air emissions. In this edition of the newsletter, a summary of the analysis for subbituminous-fired plants operating during the period from September 2017 through August 2018 will be provided. This information provides insights into which technologies are being relied upon to meet compliance as a function of air pollution control configuration. A summary of the analysis for bituminous-fired plants operating during 2017 was provided in the Summer 2018 edition of the WPCA newsletter.

### REVIEW OF COAL USED AT OPERATING EGUs

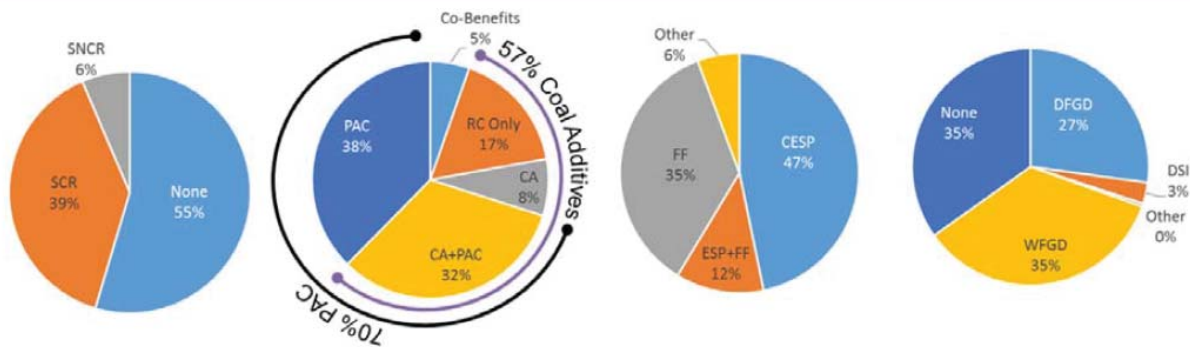
During the 12-month period included in this evaluation, 570 electric generating units (EGUs) operated and fired 613 M tons of coal, according to the Energy Information Administration (EIA)<sup>1</sup>. Ninety-four percent of these units used either bituminous and subbituminous units as their primary coal type. The average capacity factor of subbituminous plants was higher than bituminous plants (49% compared to 39%, on average), and 57% of the fuel fired by EGUs was subbituminous coal, as shown in Figure 33 and 32.

For coal-fired boilers firing bituminous or subbituminous coal, the MATS emission limit for mercury is 1.2 lb/TBtu, computed on a 30-day rolling average basis. For coal-fired boilers firing lignite coal, the MATS emission limit for mercury is 4 lb/TBtu, computed on a 30-day rolling average basis. This is a multi-pollutant rule, which can increase the complexity of finding a compliance solution. The control of particulate matter (PM) must be accomplished while controlling both acid gases and mercury (Hg).

Coal	Generating Capacity (MW)	Coal Fired (MMtpy)	Avg Capacity Factor (%)	Number of EGUs
BIT	120,642	210	39%	277
SUB	108,850	348	49%	259
LIG	12,385	51	65%	28
Other	1,229	4	63%	6

**Figure 33: Coal Use and Generation, US Electric Generating Units, Sept 17–Aug 18<sup>1</sup>**

The coal type incorporates several important parameters associated with mercury emissions and control effectiveness including the coal rank, which affects the potential for unburned carbon (UBC) in fly ash and the inherent mercury, sulfur, and halogen contents



CA: Coal Additives, PAC: Powdered Activated Carbon, RC: Refined Coal

Figure 34: Distribution of air pollution controls on US subbituminous-fired EGUs by amount of coal fired, Sept 2017-Aug 2018.<sup>1,3</sup>

in the coal. In general, higher halogen improves mercury control, and higher sulfur diminishes the effectiveness of adsorption by UBC or activated carbon for mercury control. The typical ranges of chlorine and sulfur concentration in U.S. fuels are shown below:

- Bituminous: 100-4,000 ppmw chlorine, 1.5 – 4% sulfur (dry)
- Subbituminous: <30 to 150 ppmw chlorine, 0.4 - 1% sulfur (dry)
- Lignite: 100-200 ppmw chlorine, 1 - 2.5% sulfur (dry)

A good rule of thumb is that the bromine content of coal is generally equal to 2% of chlorine content, with a range of 1-4%.<sup>2</sup> Native iodine in coal is typically lower than bromine, but has not been widely monitored sufficiently to determine typical correlations.

### AIR POLLUTION CONTROLS

There are only two pathways by which mercury can be removed from coal-fired boilers: collection of mercury that has been adsorbed on surfaces (e.g., fly ash, sorbents) and subsequently removed by particulate control devices and oxidized gaseous mercury species (collectively, Hg<sup>2+</sup>) can be absorbed in aqueous media such as in a flue gas desulfurization (FGD) scrubber.

The common mercury control strategies applied to U.S. plants fit the two pathways described above and include the following:

- **Co-Benefits:** Use the existing air pollution control devices for NOx, SOx and particulate matter with no mercury-specific controls
  1. More common on scrubbed plants firing higher halogen coal where sufficient mercury oxidation can be achieved in the flue gas, resulting in removal in a scrubber

- **Coal additives (CA):** Increase halogen content in coal to increase the fraction of oxidized mercury in the flue gas
  1. More common as a stand-alone option on scrubbed plants or combined with activated carbon
- **Powdered activated carbon (PAC) injection:** Increase the available surface area in particulate matter that can adsorb mercury
  1. Common on plants firing low-halogen fuel
  2. Often used in conjunction with coal additives or halogen-treated PAC

An overview of air pollution controls installed on all units firing subbituminous coals is shown in Figure 34 as a function of the amount of coal fired. The metric of amount of coal fired provides insights into the relative operating experience with the different control technologies. Another common parameter of analysis is the air pollution control configuration installed by each EGU, which does not provide insights into the relative size or operating capacity factor for each unit. The population distributions for the most common configurations are shown in Figure 35, calculated by the amount of

NOx Controls	PM Controls	SOx Controls	Percent of Population	Average Size (MW)
	ESP		19%	381
	ESP	WFGD	8%	492
SCR	ESP	WFGD	10%	405
	FF		5%	315
	FF	DFGD	8%	366
SCR	FF	DFGD	11%	491
Other Combinations (each < 4% of total)			39%	

Figure 35: Distribution of Air Pollution Controls and Average Generating Capacity, Subbituminous-Fired EGUs as Function of Amount of Coal Consumed, Sept 2017-Aug 2018<sup>3</sup>

coal fired. Note that the particulate control category “ESP + FF” includes both hot and cold-side ESPs, whereas the “ESP” category only includes cold-side ESPs. The mercury control category “PAC” includes both halogen treated and non-treated powdered activated carbon. The category “RC” indicates that the coal is classified as “Refined Coal” for tax purposes. For these plants, a halogen-based additive is added to the coal as part of the “refining” process.

More than half the bituminous-fired units, discussed in the Summer 2018 edition of the WPCA newsletter, have a similar air pollution control configuration: selective catalytic reduction (SCR) catalyst for NO<sub>x</sub> control, an electrostatic precipitator (ESP) for particulate control, and a wet flue gas desulfurization (WFGD) system for SO<sub>2</sub> control. However, for subbituminous fired units, no air pollution control configuration predominates. This is likely a result of the lower NO<sub>x</sub> requirements in western states where most subbituminous coal-fired plants are located and the lower sulfur content of most subbituminous coals, allowing for reliable compliance for many plants without additional scrubbing. As indicated in Figure 35, the most prevalent configuration is just a cold-side ESP without post-combustion NO<sub>x</sub> controls or SO<sub>2</sub> controls. This configuration represents only 19% of coal used at subbituminous-fired units. The next most popular configuration, representing 10% of the subbituminous coal-fired during the evaluation period, consists of an SCR and WFGD along with an ESP. Note that the EGUs that have

made the additional capital investments on NO<sub>x</sub> and SO<sub>x</sub> controls are typically larger compared to units with just particulate controls. This is especially true for EGUs with fabric filters, where units with an SCR, dry flue gas desulfurization (DFGD) system, and fabric filter (FF) are an average of 56% larger than units with FFs alone.

For most EGUs firing subbituminous coal, some supplemental mercury control technology is required to meet regulatory compliance. Specifically, for this evaluation period, only 5% of the subbituminous coal fired reported relying on co-benefits alone (no mercury-specific controls) to meet compliance. This is shown in the second pie chart in Figure 34. Note that the “co-benefit” category includes units that may use chemical additives to prevent mercury re-emission from WFGDs because this control technology is not included in the control technologies reported to the EPA. This is very different than for bituminous-fired plants, where no mercury specific controls were reported for 37% of the fuel fired. This is a very good indicator that the combination of bituminous coal characteristics, such as halogen content, and the large population of WFGDs are more amenable to mercury capture than subbituminous coal characteristics and associated air pollution controls.

**MERCURY CONTROL IN PARTICULATE CONTROL DEVICES: SORBENTS AND HALOGEN ADDITION**

Adding halogen to the coal in the form of bromine or iodine is reported to be in use at 57% of the subbituminous-fired EGUs, as measured by coal consumed, during the evaluation period. This is shown in the second pie chart in Figure 34. In general, iodine is typically about 10 times more effective than bromine for mercury oxidation. This was validated during a test conducted by Gadgil in 2015<sup>4</sup>, as illustrated in Figure 36. Furthermore, bromine is typically about 10 times more effective for mercury oxidation than chlorine. Factors that influence the selection between iodine, bromine, and chlorine include concerns about corrosion or halogen in WFGD effluent, which become more pronounced as the concentration of halogen increases, and cost. EPRI conducted an extensive study on the impacts of bromine addition on corrosion, and reported that most subbituminous plants using bromine experienced increased corrosion, especially at the air preheater<sup>5</sup>. Several plants have replaced vulnerable components with corrosion-resistant materials of construction, have optimized chemical use, or changed to a more ef-

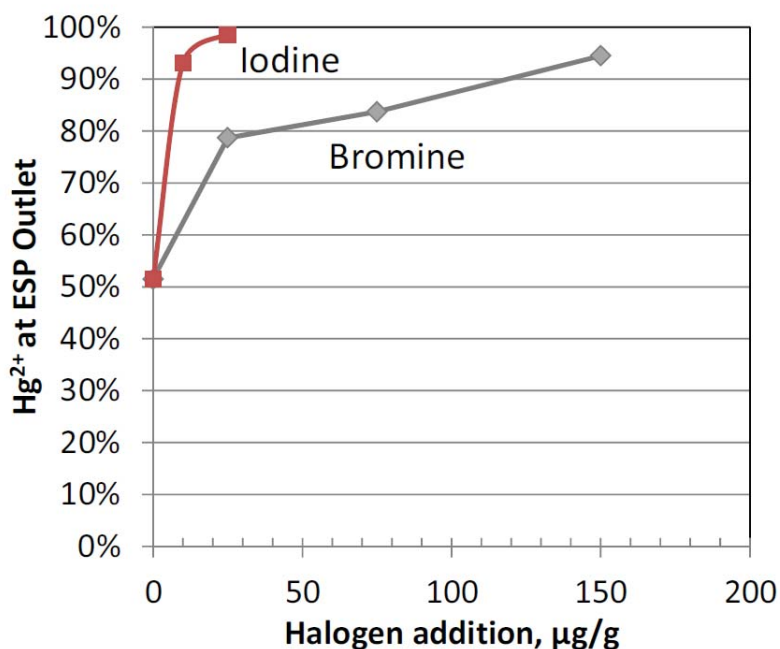


Figure 36: Relative effectiveness of bromine and iodine for mercury oxidation<sup>4</sup>

fective approach such as iodine or a combination of bromine and an advanced SCR catalyst to minimize balance of plant impacts.

Adding powdered activated carbon (PAC) to the flue gas, either alone or in conjunction with coal additives are reported to be in use at 70% of the subbituminous-fired EGUs, as measured by coal consumed, during the evaluation period. This is shown in the second pie chart in Figure 34. For those plants that do not report using coal additives in conjunction with PAC, most report using a halogenated PAC. This data is shown on Figure 37. Unfortunately, data on the amount of PAC or coal additives used is not reported to the EPA, nor is it readily available.

Evaluations conducted at individual plants provide insight into the factors that affect mercury control in particulate control devices. Key factors include:

- Operating temperature
- Cleaning frequency (for baghouses)
- Residence time (for ESPs)
- SO<sub>3</sub> (both inherent from the coal and added for flue gas conditioning)

One characteristic that will impact mercury control effectiveness, especially when using activated carbon injection, is operating temperature and the related temperature-depend

ent mercury adsorption capacity of activated carbon. Although different PAC products will have different adsorption capacity curves, an example of one non-brominated product is shown in Figure 38 on page 31 for illustration. In this case, the equilibrium adsorption capacity, or amount of mercury that can be adsorbed by one gram of carbon, decreases significantly in the typical temperature operating range for a subbituminous-fired coal plant. Note that the measured equilibrium capacity is also a function on the gas concentration, with the capacity increasing at higher gas concentrations. This is the reason that mercury removal effectiveness is typically reported as a concentration of PAC in flue gas, such as lb/MMacf, rather than a ratio of PAC to mercury, because the mass of PAC required for is not impacted significantly by the concentration of mercury in the gas.

The impact of changes in equilibrium capacity may be experienced on EGUs with fabric filters more dramatically than on units with ESPs, especially during load changes when the temperature in the fabric filter increases rapidly. This is because, in a fabric filter, the gas is essentially passing through a “fixed bed” of PAC contained in the filter cake. If PAC is allowed to remain on the filter after becoming saturated with Hg, it will release mercury, especially if the temperature increases. The mercury released will be oxidized. High oxidized mercury measured at the stack on a units firing low halogen coal (e.g. PRB), where mercury at the inlet to the

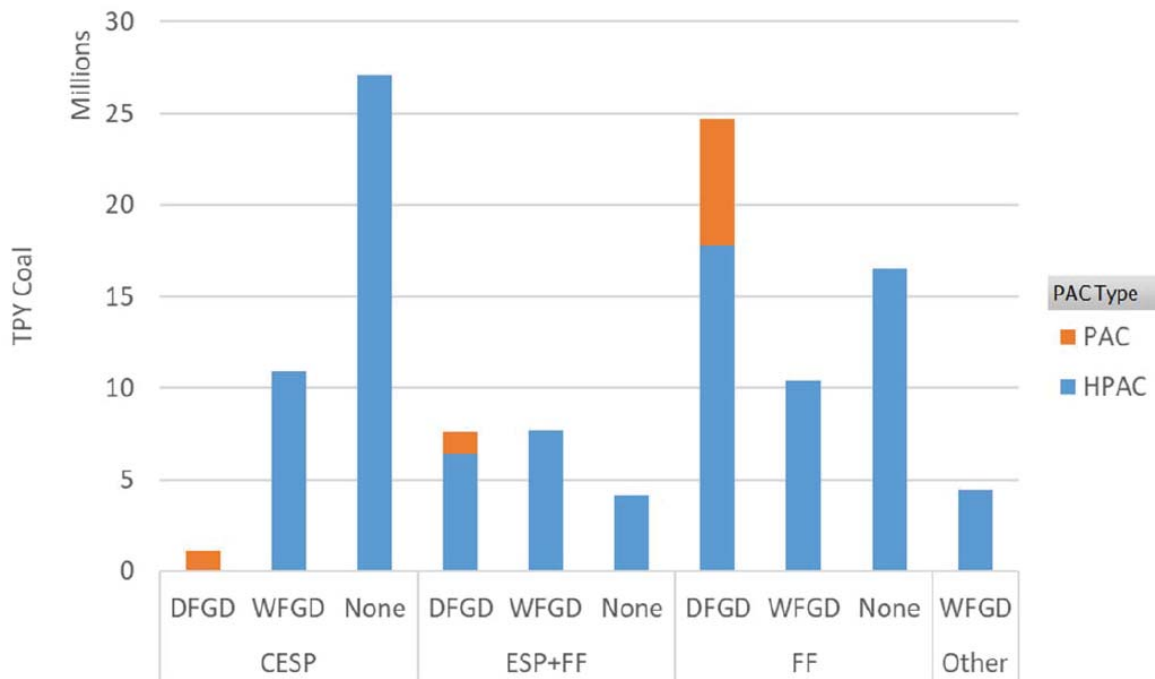


Figure 37: Coal use at subbituminous-fired EGU that report using PAC as their mercury control strategy

fabric filter is primarily elemental mercury, suggests that the PAC is adsorbing and releasing mercury from the FF. Mercury emissions data collected at one EGU with a fabric filter is presented in Figure 39 on page 32. Two data sets are included: low load and high load. The high load data clearly shows increasing emissions at higher operating temperature. This EGU was a PRB-fired boiler with an oversized fabric filter. Brominated PAC was injected at a fixed injection rate at high load and no injection at low load. Long periods between cleaning increased the likelihood that the PAC approached the equilibrium capacity for mercury, especially at higher temperatures when the equilibrium capacity is lower.

Reduced PAC loading at higher temperatures is illustrated further in Figure 40 on page 32 where the PAC loading has been calculated for the fabric filter in the previous example. The calculated loading is consistent with lab fixed-bed results. In practice, this means that more PAC must be injected at higher temperatures to maintain the same level of mercury removal. Other approaches can be used to optimize PAC usage including cleaning more frequently to remove PAC saturated with mercury. An example of the effectiveness of this approach is shown in Figure 41 on page 33. In this case, the cleaning logic was set to initiate a clean at a set pressure drop (dP) across the fabric filter. A lower pressure drop set-point represented more frequent cleaning. Additional cleaning can also be used to remove excess PAC before ramping load (*large increase in temp = potential to release previously*

*collected mercury*). Alternate PAC products with improved capacity may also be available.

### IMPACT OF SCR AND WFGD USE ON MERCURY CONTROL TECHNOLOGY CHOICE

In general, the presence of an SCR can improve the effectiveness of halogens for mercury oxidation. The configuration data was reviewed to determine whether the presence of an SCR and a WFGD impacted the fraction of units reporting that no mercury-specific controls were installed at their EGU. The data presented in Figure 42 on page 33 suggests that more than half of the units with SCRs and WFGDs rely on coal additives, including refined coal. For EGUs without SCRs or WFGDs, more than 80% of the EGUs report that PAC is part of their mercury control strategy. Also note from Figure 42 the amount of coal used at plants without SCRs that report that no mercury-specific controls are in use. More than 90% of these EGUs use fabric filters for particulate control, which can enhance native mercury removal with fly ash and improve mercury capture in downstream WFGDs.

A small fraction of subbituminous-fired EGUs rely on dry sorbent injection (DSI) for SO<sub>2</sub> control. Sodium-based sorbents have been shown to negatively impact mercury control performance, especially when used at the levels required for higher levels of SO<sub>2</sub> control. An example of the potential negative impact of trona or sodium bicarbonate injection on mercury removal performance with PAC is shown in

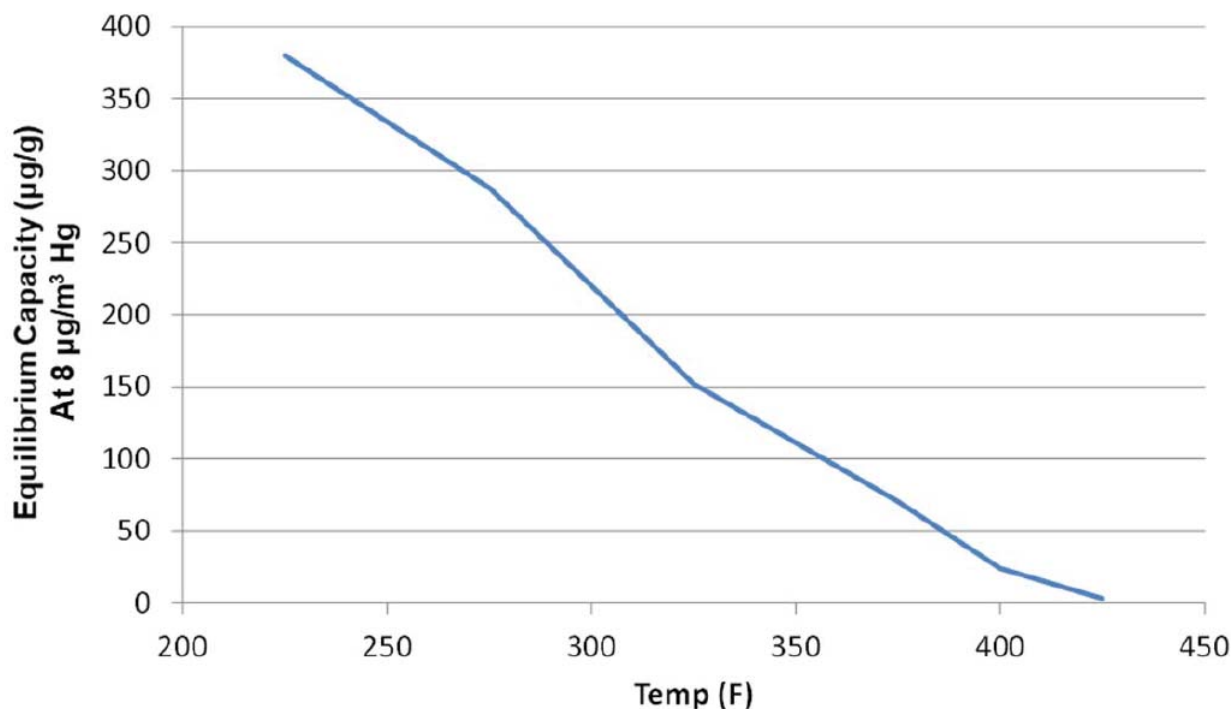


Figure 38: Impact of temperature on equilibrium capacity of activated carbon<sup>6</sup>

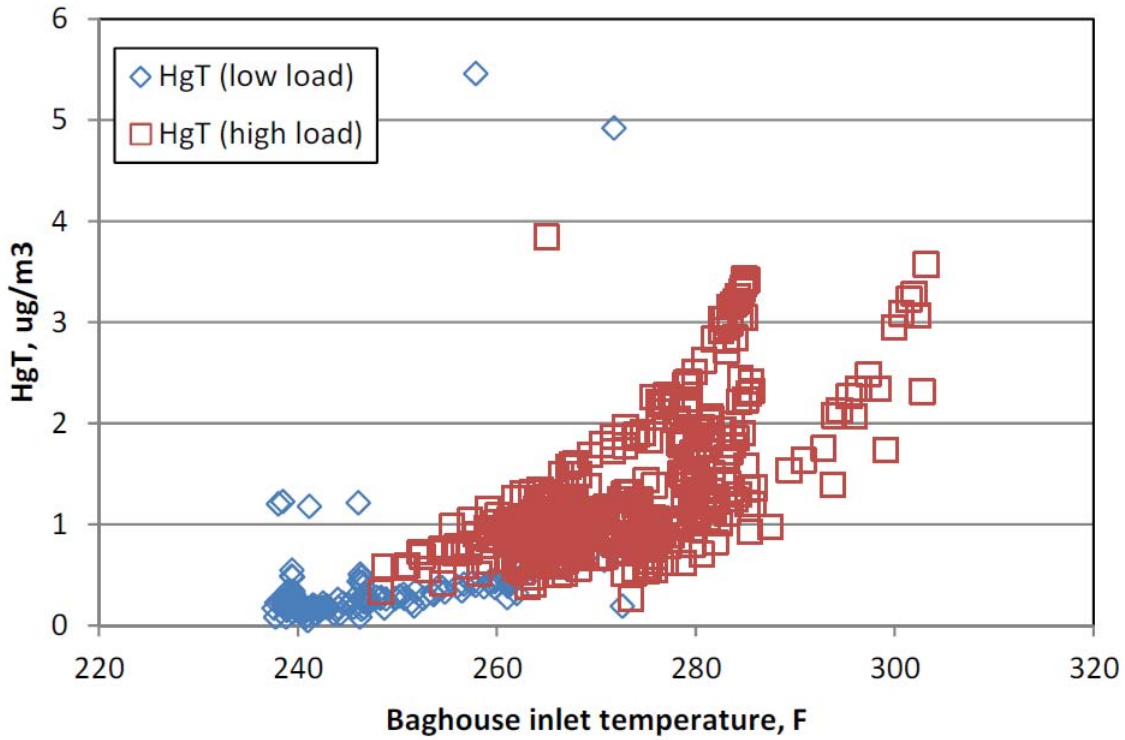


Figure 39: Fabric Filter Temperature and Mercury Emissions

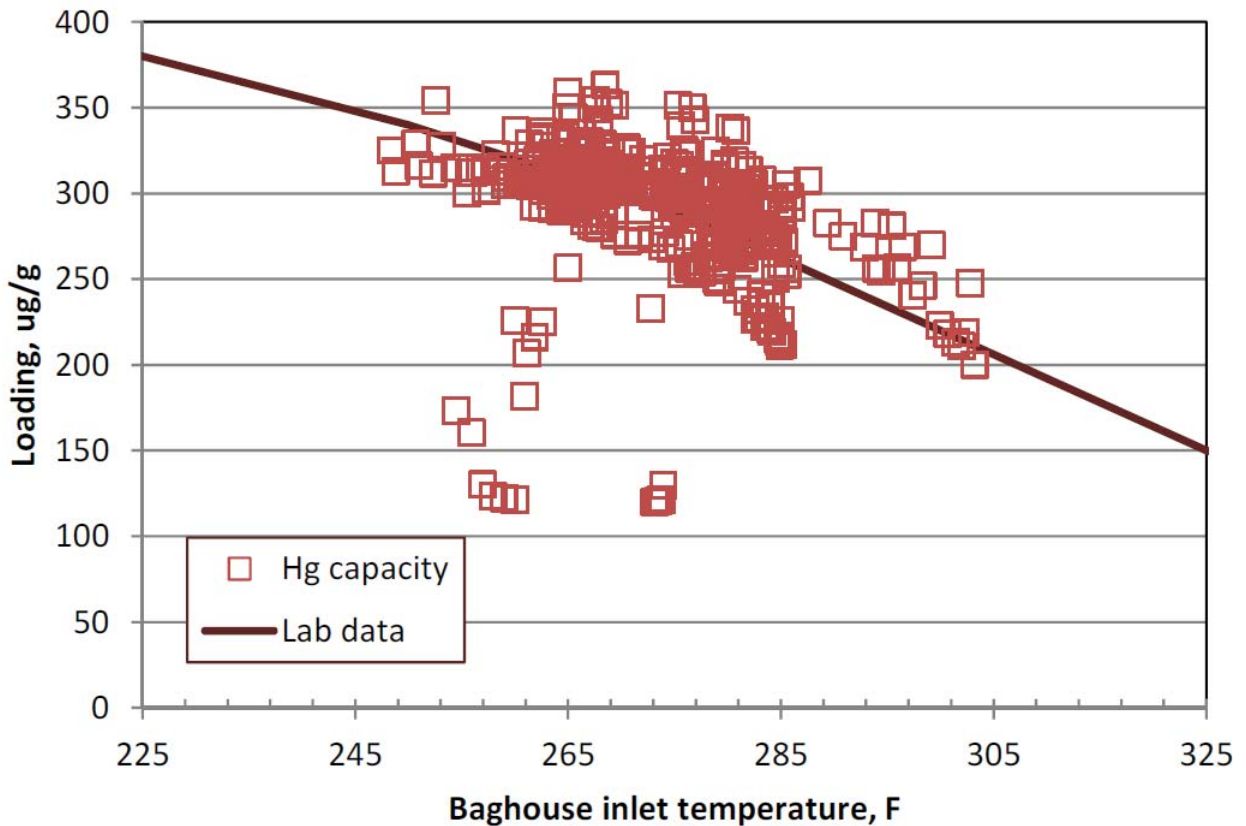


Figure 40: Estimated Hg loading on the PAC

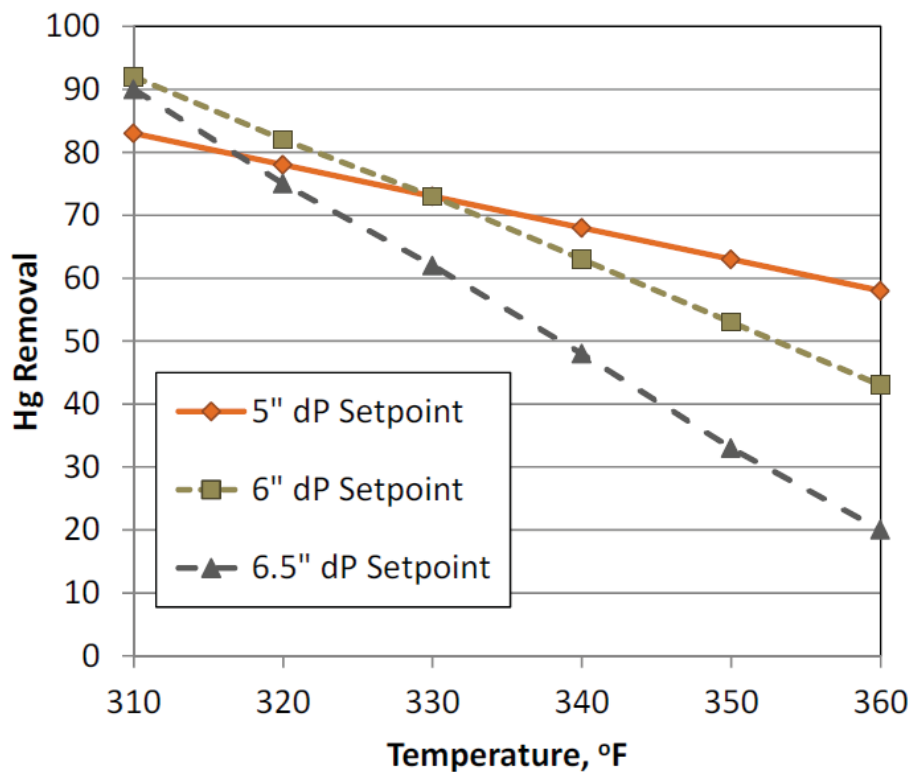


Figure 41: Improved higher-temperature mercury removal with increased fabric filter cleaning.<sup>7</sup>

Figure 43. During this test, sufficient sodium-based sorbents were used to achieve 40 to 50% SO<sub>2</sub> control, and well in excess of 90% HCl capture.

**SUMMARY**

Data reported to the EIA and EPA can be very useful in assessing the mercury compliance choices and relative effectiveness for U.S. EGUs. In general, the plants included in this assessment are well controlled using, coal additives, activated carbon, or a combination of these technologies. For subbituminous-fired units, the majority of plants rely on PAC injection and supplement mercury oxidation with halogen-based coal additives as needed.

The relative effectiveness of coal additives and activated carbon based on the specific type and quantity used is not possible to determine with data reported publicly. However, as EGUs gain experience and confidence, use behavior will trend towards the most economical solutions that reliably maintain compliance.

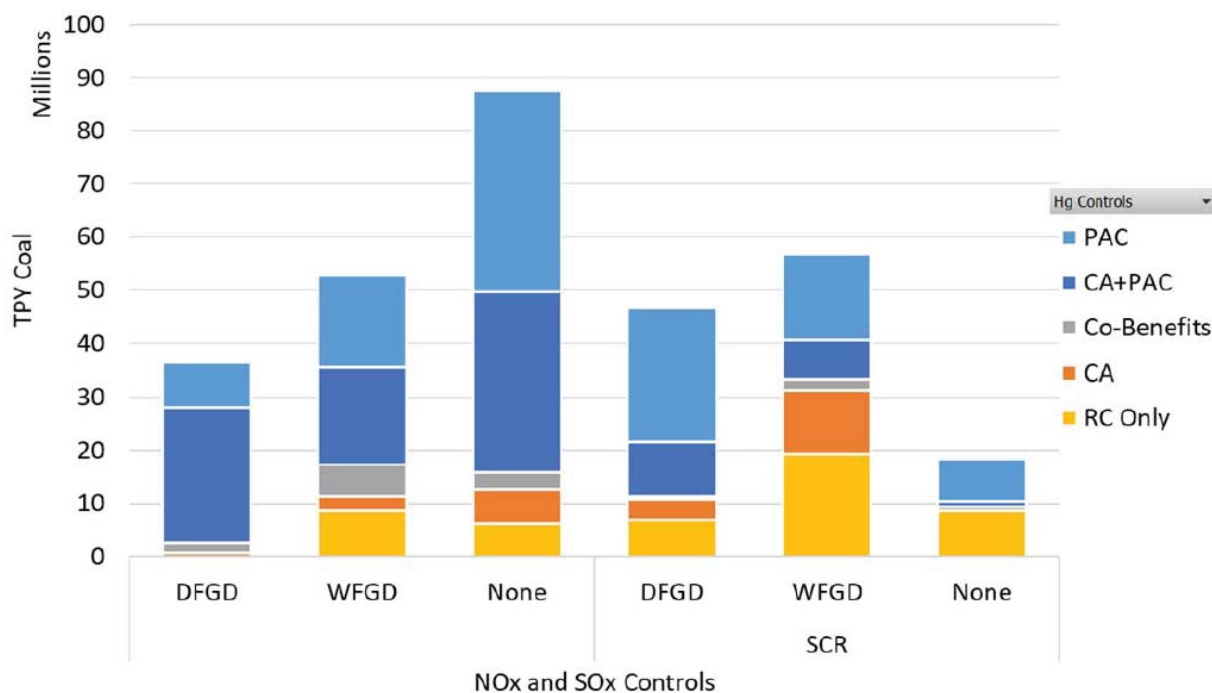
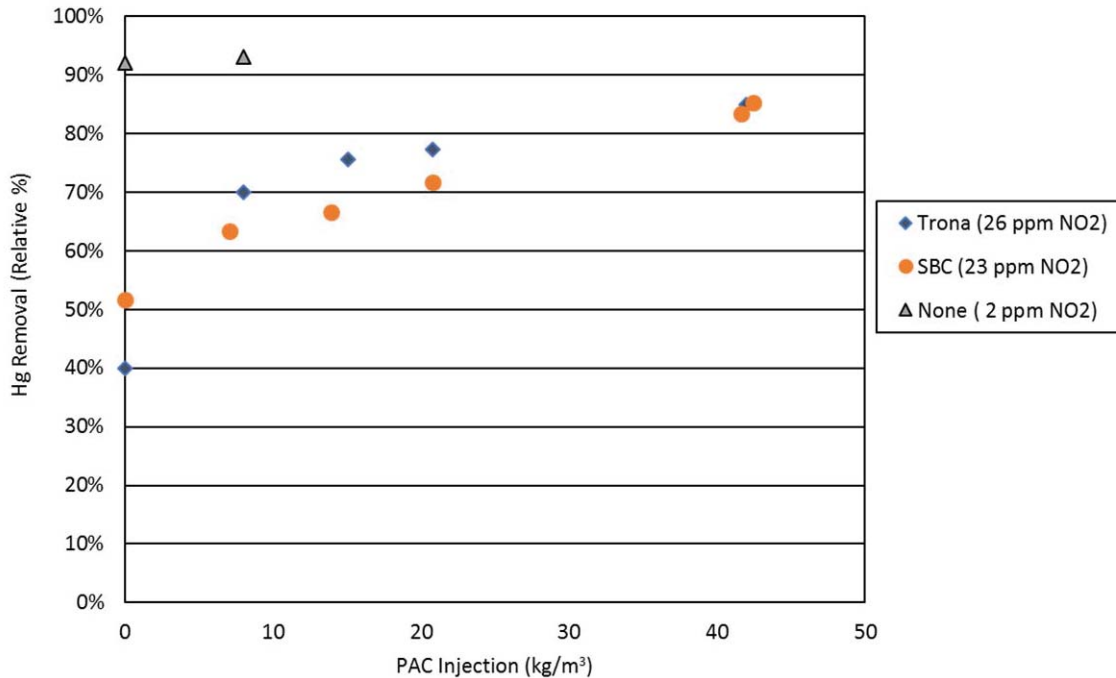


Figure 42: Comparison of mercury control technology choice for subbituminous EGUs with and without SCR and scrubbers.



*Figure 43: Example of potential negative impact of sodium sorbents on mercury capture with PAC<sup>8</sup>*

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