

Executive Summary

Hydrated Lime Dry Sorbent Injection – Beyond Regulatory Compliance

Written by Curt Biehn, Mississippi Lime Company

This article highlights the advancements in hydrated lime since it came into practice over 15 years ago in the power generation industry. New Enhanced Hydrated Lime (EHL) products are not only able to control stack SO₃ mists and APH cleanliness. Enhanced Hydrated Lime can now be efficiently injected ahead of the SCR to reduce Minimum Operating Temperature (MOT) and achieve operational cost savings by keeping coal units on-line at lower loads.

Full Story....

Flow Modeling as a Tool for WHRU Performance Optimization

Written by A. Gupta, M. R. Gentry, Airflow Sciences Corp.

Both CFD and physical flow modeling were used to refine the design of a Waste Heat Recovery Unit prior to construction. Several design elements were used to promote optimum heat transfer despite the non-uniform gas turbine profile upstream. After optimization, the unit has been running well for 4+ years.

Full Story....

FCM Mill Optimization for SBC Injection

Written by Alan Heuer, Nol-Tec Systems & Tomas Johansson, Sturtevant FCM Air Classifier Mill Systems

Air classifier mills used in conjunction with dry sorbent injection systems reduce particle size and maximize sorbent efficiencies. Mitigation of SO₂ using Sodium Bicarbonate (SBC) is enhanced when milled to a smaller particle size, increasing the available sorbent surface area, improving binding of pollutants, and maximizing sorbent efficiency.

Full Story....

Process Sampling and Chemical Analyses for Cost-effective Emissions Control on Coal Units

Written by Cassandra Hutson, AECOM Process Technologies

As coal-fire power plants strive to comply with existing environmental regulations and lower costs to remain viable, the collection and analysis of samples for chemical constituent concentrations is a valuable tool to support decision making. This article illustrates two examples of the effectiveness of chemical analysis for problem resolution or cost reduction efforts.

Full Story....

Hydrated Lime Dry Sorbent Injection Beyond Regulatory Compliance

Written by Curt Biehn, Mississippi Lime Company

When dry sorbent injection (DSI) of hydrated lime came into standard practice over 15 years ago, the intent was to control acidic species such as sulfur dioxide, sulfuric acid mist (SAM), and halogenated acids present in flue gas. Standard hydrated lime available in industry at that time was not very effective for control of SO₂ and generally confined to niche industrial applications, often as a slurry of hydrate where the additional moisture made hydrate usage rates more reasonable but still not effective to use for large scale utility usage for high level SO₂ control. The advent of selective catalyst reduction (SCR) and wet limestone scrubbing for NO_x and SO₂ control, respectively, created an immediate need to control sulfuric acid mist emissions at the stack.

Early tests in the 2000's showed that standard hydrated lime performance for DSI removal of SAM was not economical compared to other options. Subsequent testing with higher quality hydrated lime found SAM removal performance to be acceptable in many cases. These types of hydrated lime were classified as Flue Gas Treatment (FGT) grade and characterized by a minimum surface area (at least 18 m²/g) and purity (over 90% calcium hydroxide). FGT grade hydrate offered end users acceptable and economical plume control at the stack while also providing fly ash without leachable salts. Limitations still existed for extremely high SAM removal rates (> 95%) or units with marginal electrostatic precipitators (ESP). However, some utilities with marginal ESPs dealt with that by injecting hydrated lime after the ESP and prior to the wet scrubber.

In 2009, demonstration data was reported on injecting hydrated lime prior to the air preheater (APH). These tests showed that sulfur trioxide (SO₃) that existed prior to the APH could be effectively controlled, giving the end user the benefit of environmental control of SAM

plus earlier corrosion protection in ductwork. Subsequent, longer demonstrations of pre-APH injection of hydrate showed that differential pressure buildup in the APH was easily controlled and did not carry the risk of byproduct formation and deposition in the ductwork or APH internals. This offered end users significant economic advantages over sodium sorbents, which generate byproducts that deposit in ductwork when not operating at high stoichiometric ratios.

A few years later, development of next generation hydrated limes aimed at better performance in DSI applications led to more field demonstrations of performance benefits. This next generation of hydrates have been dubbed Enhanced Hydrated Lime (EHL) to cover the particle modifications made by the Lime manufacturers competing in the market. The chief advancements came in the way of particle size, reactivity, and/or surface area, and manufacturers stress different factors. While EHL came at a higher cost, they also offered benefits to the end users through higher removal rates of acid gases. The potential to use less sorbent annually was economically attractive, not only because of sorbent savings but also the associated direct and indirect costs of transportation, loading and unloading, and reduced

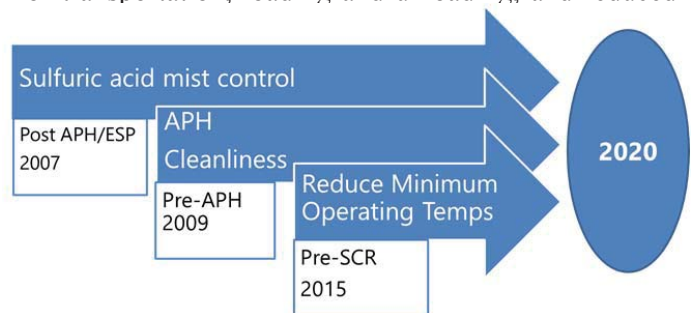


Figure 1: Progression of Hydrated Lime DSI to the Utility Industry

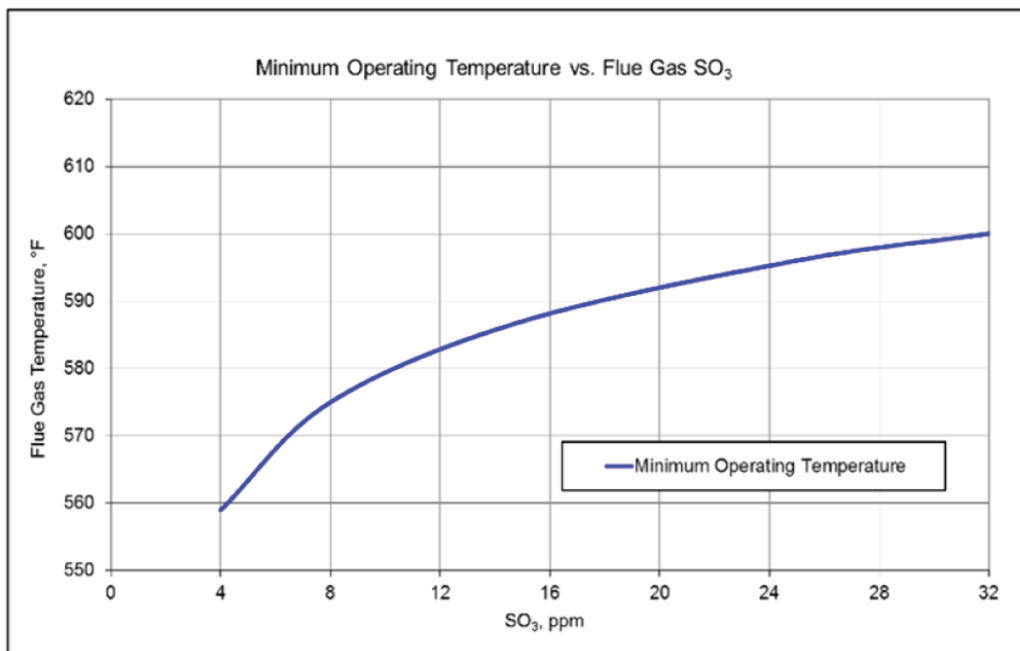


Figure 2: Example of Effect of SO₃ Level on Flue Gas Minimum Operating Temperature for an SCR

truck traffic. Additionally, higher performing hydrate reduces feed rates and eases particulate loading on marginal ESPs. Overall, about over 70% of the Utility DSI industry uses EHL.

EHL with high reactivity capabilities are especially attractive to applications injecting upstream of an APH. The rapid in-flight capture of SO₃ between the injection point and the inlet to APH can provide for low SO₃ (< 10 ppm) levels entering the APH. With low levels of SO₃, Utilities can reduce the APH outlet temperature or eliminate the use of steam coils to maintain APH differential pressure.

In the past few years, natural gas pricing and the rise of

renewables have reduced the time most coal plants operate at full load. Under extreme cost pressures, Utility coal-fired generation have searched for methods to control cost while operating a higher percentage of time at minimum load. The best method of reducing minimum operating temperature is to reduce the SO₃ content of the flue gas stream prior to and through the SCR. Catalyst manufacturers base their recommendation for minimum load on the flue gas condensable level, which is generally a function of inlet SO₃, inlet NH₃, and NH₃ slip, plus an additional 25 °F from the bulk value to account for capillary condensation. Using hydrated lime to reduce the SO₃ level (condensables) allows the Utility to drop minimum load by several MW.

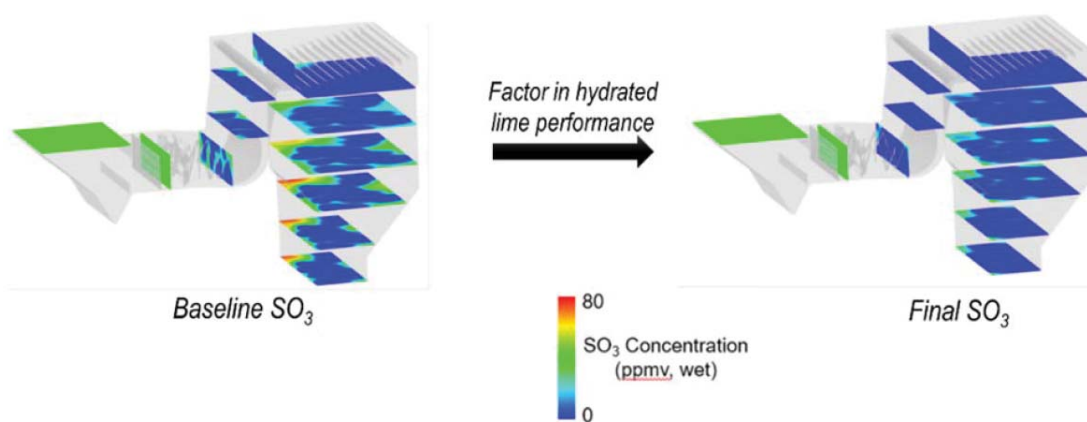


Figure 3: CFD Model of Pre-SCR DSI Showing Effect of Hydrated Lime Performance Characteristics on SO₃ Removal. Factoring hydrate reactivity predicts high removal of SO₃ beyond simply considering hydrate physical properties (Courtesy Reaction Engineering International)

A plant running at a lower minimum operating temperature burns less coal, generates less CO₂, and requires less SO₂ scrubbing reagents. There are significant cost savings attainable by lowering plant minimum operating temperature. *Figure 2* shows an example where a unit has a minimum operating temperature of 600 °F with untreated flue gas having 32 ppm SO₃. Using hydrated lime pre-SCR to reduce the SO₃ level to 4 ppm allows the unit to operate 40 °F lower, with a minimum flue gas temperature of ~ 560 °F.

The technology is available with DSI to make this possible. Improvements in hydrated lime conveying best practices are understood. More effective injection devices/static mixers can aid dispersion of the sorbent and ensure good flue gas coverage. Computational fluid dynamic (CFD) modeling can now incorporate not only the particle dispersion but also the reactive properties of the hydrate from the injection point through the APH. The development of highly reactive hydrated lime has certainly improved the capability of capturing high levels of acid gas in a short time prior to and through the SCR catalyst layers. Finally, in-line monitoring¹ of flue gas condensable species provides real time feedback that the DSI is performing as intended and downstream equipment is protected.

CASE STUDY – PRE-SCR INJECTION OF ENHANCED HYDRATED LIME

A recent demonstration identified the benefits attainable by using EHL DSI with injection prior to the SCR. The unit was utilizing trona injected post-APH for control of SAM. The moderately sized unit (< 300 MW Gross) experienced gradual APH fouling and wanted to evaluate EHL as a means of controlling the differential pressure buildup over time. In-

jecting EHL prior to the SCR gave the unit an opportunity to explore the potential of reducing the existing minimum load of ~ 90 MW.

Temporary feed equipment was used for the demonstration, including a vertical silo, blower trailer equipped with PLC to operate the equipment, plus hoses, splitters, and lances for injection of EHL. This demonstration used Mississippi Lime High Reactivity Hydrate (HRH) in conjunction with Breen probes to monitor flue gas condensable characteristics. The results, shown in *Figure 4* below, show that at high load, flue gas formation temperatureⁱⁱ was 260-265°F range with no hydrated lime feed. Adding HRH at 400-700 lb./hr. reduced condensable formation temperature by ~ 30°F. Additional HRH (> 750 lb./hr.) drove condensable formation temperature below 190°F.

Plant reaction supported the data from the probes: during the demonstration, APH differential pressure stabilized instead of its usual upward climb. ID fan power consumption was reduced as a result of the stabilization of APH differential pressure. APH soot blowing frequency was minimized as well and this should improve APH basket life. As a benefit to the plant, the optimum feed rate for HRH with pre-SCR injection was roughly equivalent to the baseline trona feed rates for post-APH injection. Converting to hydrated lime will allow the site to pay less for annual delivered sorbent cost plus open up potential ash sales that were limited due to the presence of leachable salts from the use of trona.

The release of condensables during load ramp (also known as “morning sickness”) occurs as the boiler’s rise in output raises flue gas temperature and volatilizes any SO₃, ammo-

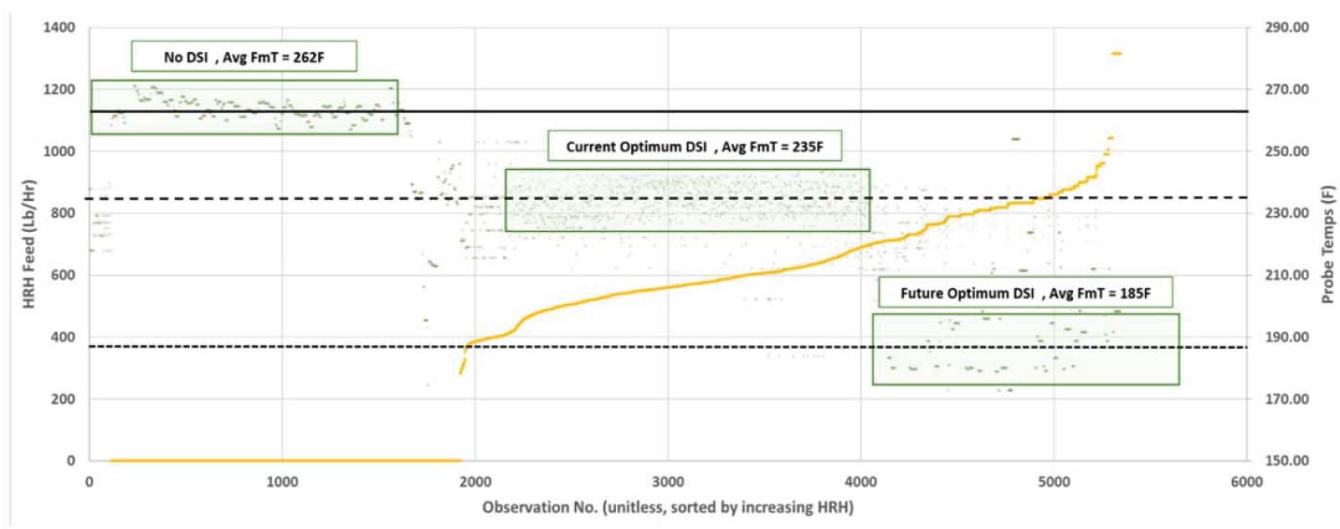


Figure 4: Plot of Condensable Formation Temperature versus HRH Feed Rate; High Load Conditions

nia, or ammonium bisulfate that has condensed on the SCR catalyst plates during the reduced temperatures of low load operation. If SO₃ is controlled with pre-SCR hydrate injection, the morning sickness will not be evident on the Breen probe or visually detectable at the stack. Over the multi-week demonstration, the plant continued feeding hydrate around the clock. There were no issues feeding hydrate during low load operations. When the plant began increasing load, there was not a release of condensables during that ramp, which is typically evident for plants who feed hydrate post-SCR. There is optimism that the plant can reduce minimum load with full time operation of DSI with HRH during low load periods.

We have chosen to adopt 25% of the Unit's Maximum Continuous Rating -- the maximum load it can generate on a continuous basis -- as the potential minimum load at which the unit could reasonably operate. Examining the plant's load profile for a year, we found that they spent 1,798 hours operating a minimum load (Figure 5). This translated to 57,800 MWhr at minimum load. Applying the 25% factor and comparing that to the existing minimum load indicates the difference between the black (existing) and red (potentially attainable) minimum loads. In total, this means that ~714,400 mmBTU is 'wasted' operating at the higher minimum load and attainable savings using pre-SCR injection of hydrated lime. There is also a reduction of ~75,000 tons/yr of carbon dioxide emissions. These are examples of the significant benefits attainable with lowering the minimum operating temperature.

CONCLUSION

Continued advancements and proof of concept demonstra-

tions exhibit that DSI using enhanced hydrated lime allows Utilities to recognize operational cost savings from a key environmental control system. These advancements help keep coal-fired generation competitive under increasing cost pressure and reduced technical staff.

REFERENCES

i The Real-Time Measurement of Sulfur Bearing Vaporous Compounds ("SO₃", sulfuric acid, ammonium bisulfate) and Its Application for Use for Process and Environmental Control Written by Daniel T. Menniti; Breen Energy Solutions, WPCA News, Summer 2019.

ii The relationship between SO₃ and dew point has been known for decades and was best described by the Verhoff-Banchero equations. However, Dew Point is a static measurement based on the balance between evaporation and condensation from a surface. The Breen probe measures this dew point, but it also provides insight into the kinetic side of the process. The formation temperature is lower than the dew point and represents the temperature of a particle or metal surface where a moving gas will condense. It is useful in identifying the depth within the air heater where condensable material will deposit.

*For more information, please contact
Curt Biehn at crbiehn@mlc.com*

BIOGRAPHY



Curt Biehn is Technical Director for Mississippi Lime Company. He has been with Mississippi Lime since 2008, focusing on air pollution control in Dry Scrubber and Dry Sorbent Injection systems. Curt has worked with the industry optimizing hydrated lime DSI including conveying, injection prior to the Air Preheater, and the development of enhanced hydrated limes. He holds a B.S. degree in Chemistry

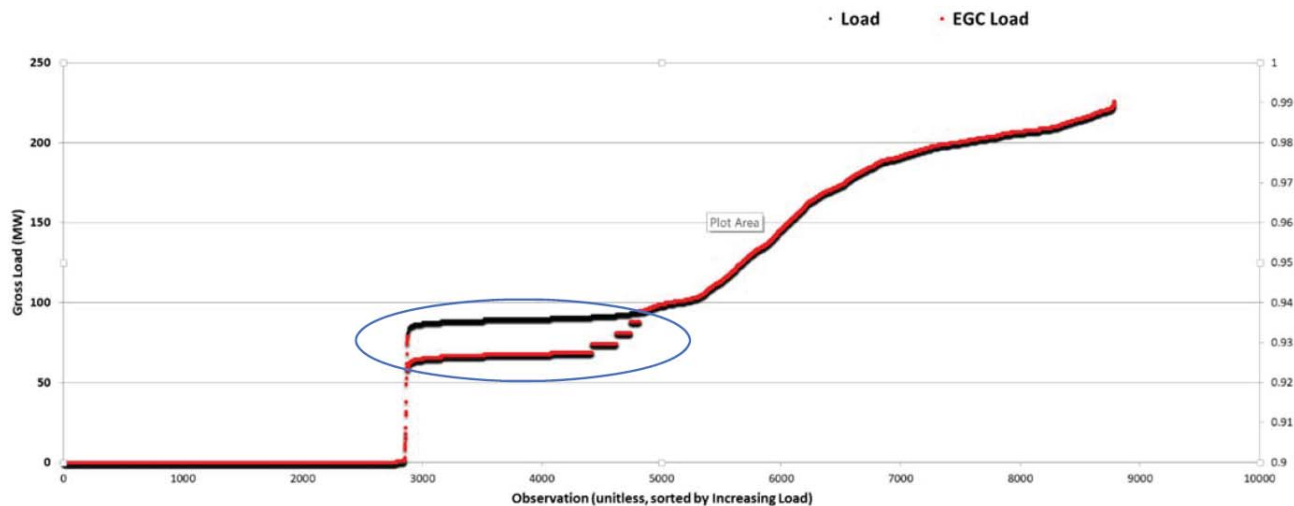


Figure 5: Load Profile of Demonstration Unit; Observations are Hourly. Circled region identifies potential lower minimum load potential

from SIU – Edwardsville and a M. S. in Organic Chemistry from The Ohio State University. Prior to joining Mississippi Lime, Curt worked in the Specialty Chemical industry in several roles, including Technical Services, Operations, Quality Management, and Applications Development.



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Flow Modeling as a Tool for WHRU Performance Optimization

Written by A. Gupta, Petro-Chem Development and M. R. Gentry, Airflow Sciences Corporation

INTRODUCTION

Greenhouse gas (GHG) emissions have become a growing concern for many industrialized countries over the past few years. Beyond the specific issues of GHG and general environmental considerations, there is a global tendency for improved energy efficiency. Indeed, whether the price of energy is high or low, controlled and reduced energy consumption will naturally improve operators' margins. As a result, use of energy is minimized by heat integration, heat recovery and reduction in heat loss to atmosphere.

A Waste Heat Recovery Unit (WHRU) is a type of heat exchanger which recovers waste heat from hot flue gases and integrates heat in to the balance of plant operations. The WHRU can generate steam/superheating steam as well as heat thermal fluid, natural gas, various hydrocarbon fluids, and Regen Gas (cyclic operation).

WHRU is utilized at a wide range of industrial applications, including:

- Liquefied Natural Gas (LNG) plant
- CO Incinerator Boilers for FCC
- Catalytic Reforming Units
- Hydrocracker Units
- Ethylene Crackers
- Steam Methane Reformers

An LNG plant utilizes gas turbines (GT) to generate power and run turbines/compressors for refrigeration systems. The GTs burn natural gas to generate power, and waste heat in the hot flue gas (at a temperature of approximately 1000°F/538°C) is recovered in a WHRU downstream of the GT by heating a thermal fluid.

Normally a WHRU consists of GT exhaust ductwork, a silencer to reduce noise, a bank of heat recovery coils (finned) and an exhaust stack. The efficiency of heat transfer depends upon the amount of surface area provided, the temperature differential available and uniform distribution of flue gases over the finned coils.

Petro-Chem Development CO., Inc. is a supplier of WHRUs for LNG plants. It has supplied a large number of units, now commercialized under the Heurtey Petrochem Solutions

brand owned by Axens Group. A case study is presented to show the effectiveness of flow modeling in optimizing performance of a WHRU.

CASE STUDY

In this case study, flue gases from a GT are used to heat a thermal fluid (hot oil) and, in turn, this thermal fluid will provide heat (approx. 200 MMBtu/hr) to various other units and equipment in the LNG plant. The flue gas distribution pattern from the exhaust of the GT was not uniform. Optimal operation of the WHRU is dependent on the gas flow characteristics across the tube banks of the hot oil coils.

A wireframe of the baseline design is shown in *Figure 6*. The hot gas exiting a gas turbine (GT) flows through the WHRU, heat transfer occurs across the tube banks, then the gas exits the stack.

Airflow Sciences Corporation (ASC) was contracted to carry out computational fluid dynamics (CFD) and physical model flow studies in order to optimize flow control devices within the WHRU system. The CFD model was primarily used to design flow control devices and assess velocity patterns.

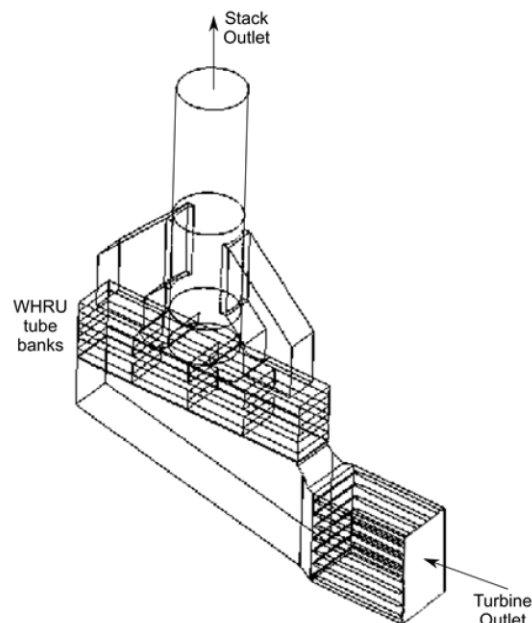


Figure 6: Flow through the baseline design of the WHRU

The physical model was used for confirmation of the flow control device design and for assessment of velocity uniformity. The primary goal of the project was a uniform gas velocity distribution upstream of the tube banks for improved heat transfer, with a secondary goal of minimizing pressure loss.

BASELINE DESIGN

To accurately assess the flow characteristics, both the CFD and physical models include;

- Ductwork downstream of the turbine (with silencer),
- The WHRU inlet plenum and tube banks,
- The exhaust stack.

Additionally, any internal flow control devices such as vanes and gas distribution devices required to improve flow were incorporated into the models.

The gas flow exiting the gas turbine is highly turbulent and energetic. The primary challenge of the design process is to sufficiently control this flow. The flow enters a duct silencer, with horizontal panels, before exiting into a plenum upstream of the heat transfer tubes.

The Baseline geometry included the duct silencer, but no other flow control devices. The turbine exhaust gas (TEG) flow is highly stratified, with much higher velocities on the right side of the duct, as shown in *Figure 7*. This stratifica-

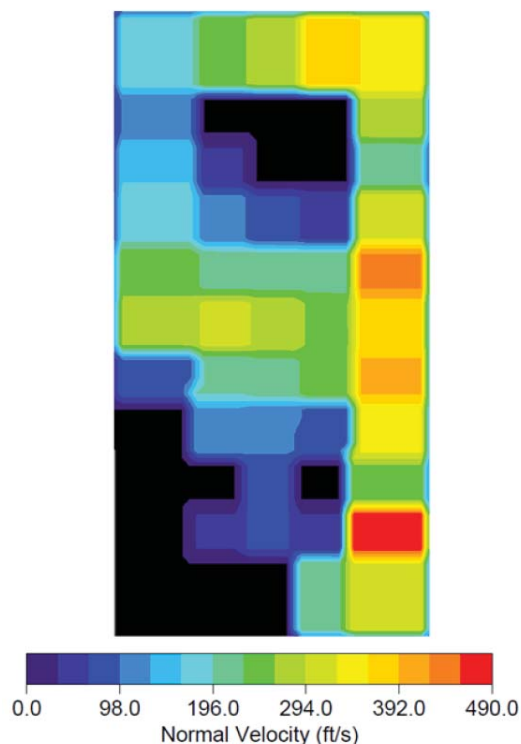


Figure 7: TEG velocity profile

tion is due to the side turbine outlet diffuser, which has limited flow control devices and results in the gas flow bunching up on one side of the duct. One of the primary challenges of the design was to reduce this significant side-to-side TEG stratification prior to the tube sections.

Since the design objective is to produce uniform and optimized heat transfer through the tube banks, the velocity profile through the WHRU is closely monitored. The baseline CFD model centerline velocity profile is shown in *Figure 8*. In addition to the side-to-side issues, significant stratification is evident vertically through the silencer baffles. The velocity is thus very non-uniform at the inlet to the tube banks. Note the extremely low velocities (dark blue), indicating a dead zone with little flow.

Figure 9 on page 8 provides CFD results for velocity at the plane immediately upstream of the tube banks. In this plan view, side-to-side stratification is evident, with higher velocities on the right side of the unit (top of the Figure) due to the TEG profile. The red circles indicate the locations of velocity measurement points. This “grid” of points is used to provide statistical values of flow uniformity, as well as a comparison to field test or physical model flow data. The velocity uniformity is reported as %RMS (root means square), also referred to as Coefficient of Variation (CV). The %RMS is a normalized value, defined as the standard deviation of

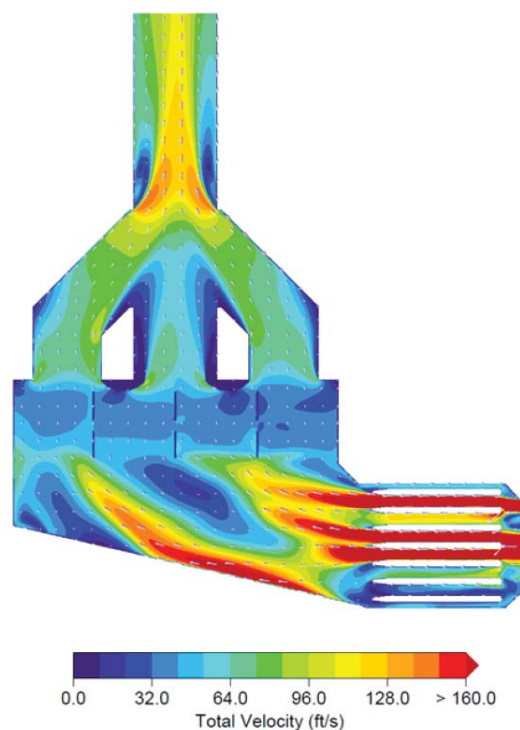


Figure 8: Centerline velocity profile of the baseline WHRU design without the flow control devices.

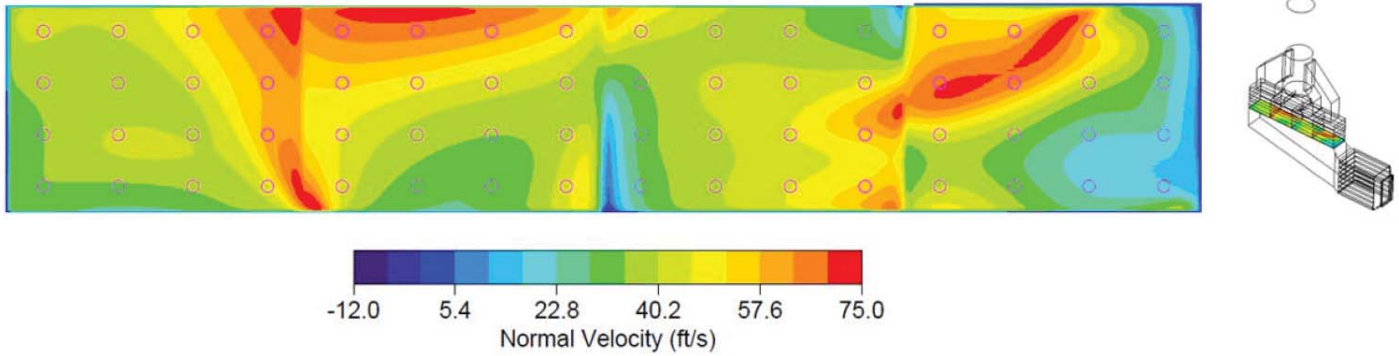


Figure 9: Velocity just upstream of the tube bank in the baseline design.

velocity divided by the average velocity over the selected grid of points. A typical goal for %RMS is less than 15% in order to achieve uniform flow and efficient heat transfer. For this baseline WHRU model, the velocity uniformity at the tube bank inlet plane is 27.9%, well outside the goal.

FINAL DESIGN FROM CFD ANALYSIS

ASC carried out different CFD simulations resulting in the addition of several flow control devices to create a final design. These changes are shown in *Figure 10* and include:

- Perforated plate
- Ladder vanes
- Inlet duct addition of kicker plate
- Layout of silencer baffles

Figure 11 shows the CFD centerline velocity profile for the final design. The ladder vanes were added upstream of the tube banks in order to better distribute the gas flow while reducing the gas velocities. The perforated plate was added just downstream of the turning vanes to further smooth out the flow profile heading into the tube banks.

The purpose of the perforated kicker plate at the entrance of the silencer is to mitigate the effect of the stratified TEG flow, spreading the flow out prior to the duct silencer.

The final CFD profile upstream of the tube banks can be

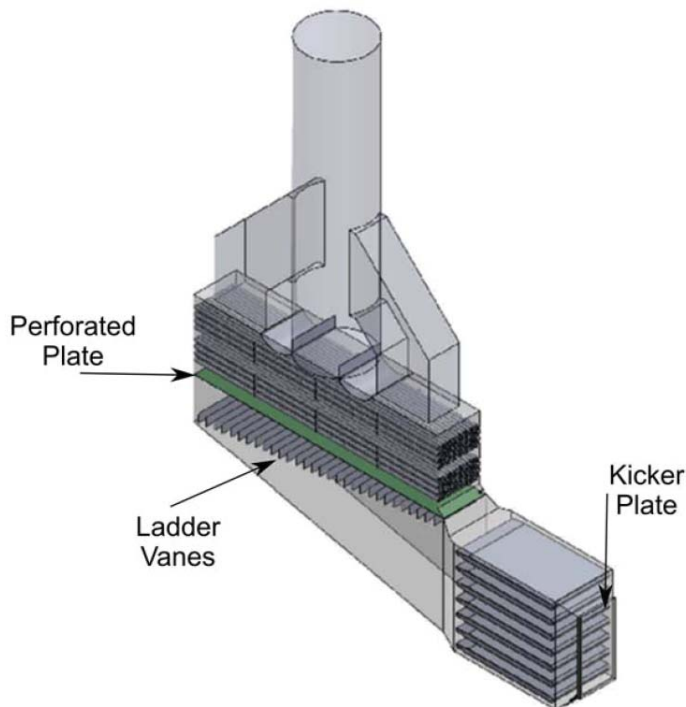


Figure 10: Isometric view of the final design of the WHRU

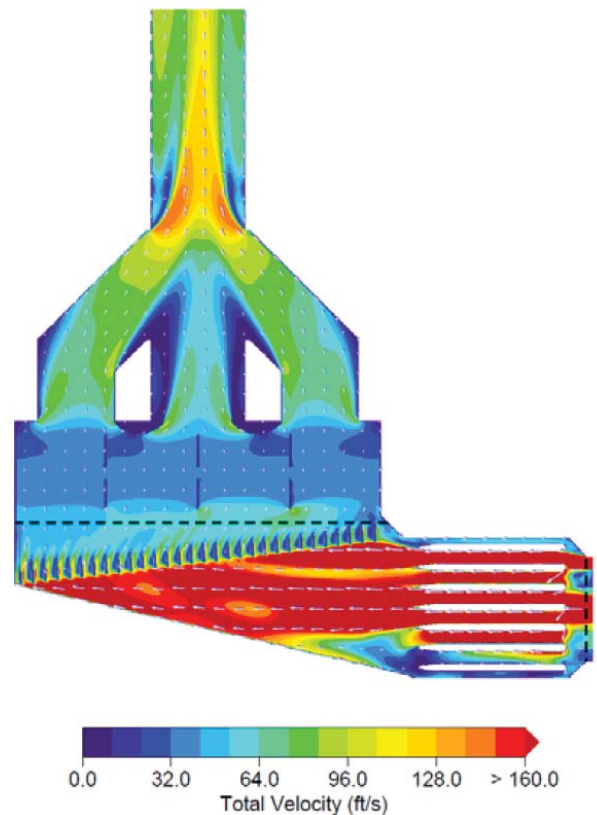


Figure 11: Centerline velocity profile of the final WHRU design.

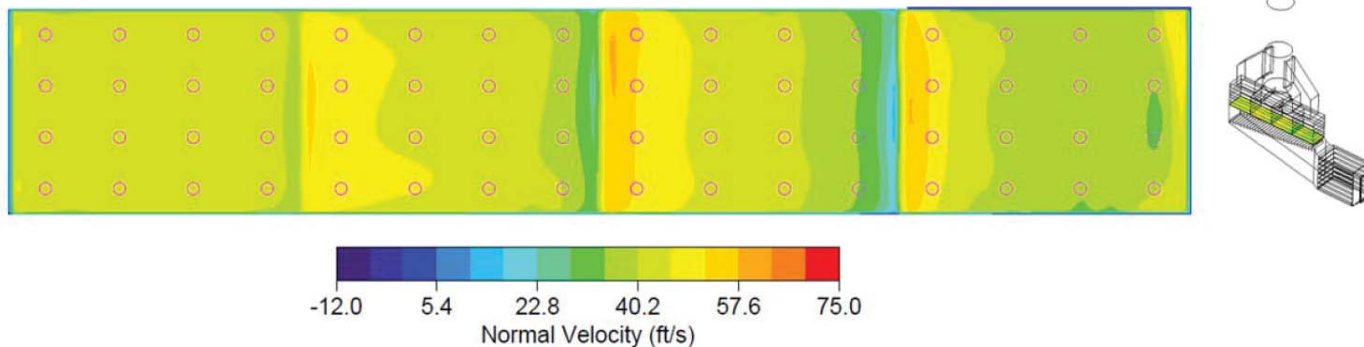


Figure 12: Velocity just upstream of the tube bank in the final design.

seen in *Figure 12*. The increased uniformity near the lower tube bank is evident, as indicated by the elimination of the higher velocities (orange and red colors). The %RMS in the final design at the plane just upstream of the tube banks was 11.2% compared to 27.9% in the baseline CFD version, a significant improvement.

The uniform velocity field will result in improved heat transfer performance, as the mass flow of gas past each heat transfer tube will be more even, rather than having some areas of high or low velocity where the heat transfer would not be optimized. Potential structural issues are also mitigated, as stresses due to uneven thermal expansion are reduced. Although the addition of flow control devices resulted in a larger system pressure loss, the improved flow provided by these devices resulted in a reduction in pressure loss through the tube banks. Overall the pressure loss target was still met.

PHYSICAL MODEL ANALYSIS

A scale model was built of the final design geometry to confirm the findings of the CFD analysis. The physical model is the same geometry as the final CFD design, but at a 1/12 scale. The model was primarily constructed of clear acrylic. The flow control devices, tube banks, and silencer are constructed of formable plastic, acrylic, sheet metal, or wood. The physical model data were collected at scaled operating conditions that could be compared to the CFD.

Velocity and pressure measurements were taken at critical planes in the model, including:

- 1. Upstream of silencer/model inlet
- 2. Downstream of silencer/WHRU inlet
- 3. Upstream of tube banks
- 4. Downstream of tube banks
- 5. Stack outlet

MODELING SUMMARY

The goal of the project was to optimize the following requirements:

- Uniform flue gas velocity distribution upstream of the lower tube bank (Target: 15% RMS)
- Optimize system pressure loss

Both the CFD model and the physical model results confirm that the above requirements were met with the final design geometry.

The WHRU was constructed with these design elements. Feedback from the operating plant indicates WHRU is operating within design parameters.

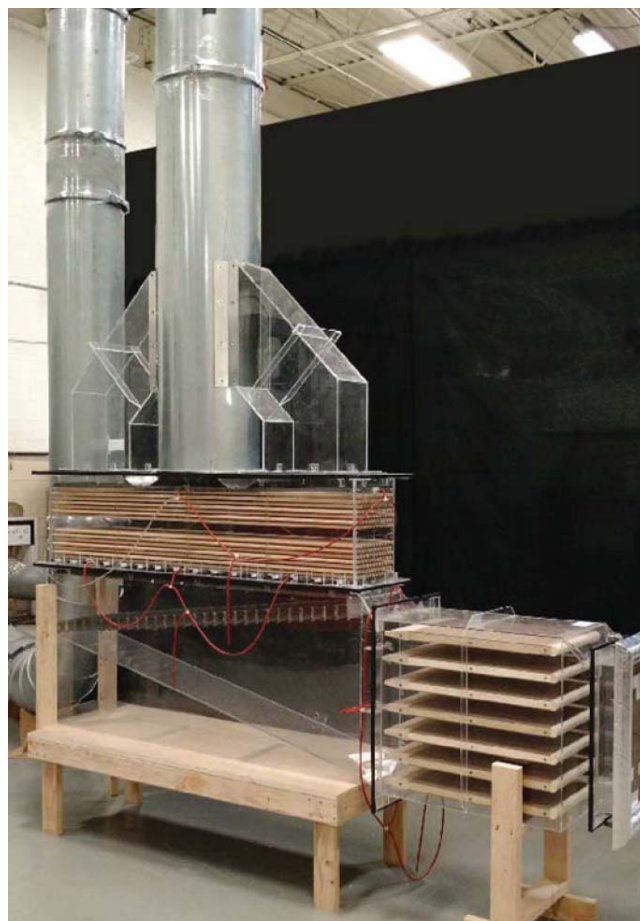


Figure 13: Overview of the physical model

For further information contact Matt Gentry at
mgentry@airflowsciences.com

BIOGRAPHY



Mr. Matthew R Gentry, received his M.S.E. in Aerospace Engineering from the University of Michigan, with a specialization in structural mechanics. He has worked for ASC for over 15 years, performing flow modeling as well as both laboratory and field testing. He has served as project manager for HRSO, WHRU, SCR, and sorbent injection projects, helping to optimize performance and pollution control in a wide variety of industrial applications.



Amit Gupta holds a BS degree in chemical engineering from the department of chemical engineering and technology, Panjab University, India. He has more than 24 years of experience in the design of process fired heaters, cracking furnaces and air-emission reduction systems. He held positions at Engineers India Limited (EIL) and Technip (KTI Corp) before joining Petro-Chem Development Inc., later bought by Heurtey Petrochem which was in turn acquired by Axens in 2017. Mr. Gupta is the Director of Furnace Technology and Proposal with Petro Chem Development Co., Inc



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3850 Bordeaux Drive
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FCM Mill Optimization for SBC Injection

Written by Alan Heuer, Nol-Tec Systems, Inc. & Tomas Johansson, Sturtevant FCM Air Classifier Mill Systems

INTRODUCTION

Air classifier mills used in conjunction with dry sorbent injection systems reduce particle size and maximize sorbent efficiencies. Mitigation of SO₂ using Sodium Bicarbonate (SBC) is enhanced when milled to a smaller particle size, increasing the available sorbent surface area, improving binding of pollutants, and maximizing sorbent efficiency.

Some pollutants such as SO₂ require significant amounts of continuously injected sorbent, therefore it is critical to optimize the operation of the mill using field gathered test data.

The objective of this standard application trial was to determine the maximum feed rate at which the mill will produce the desired particle size distribution, and the maximum range of feed rates at which the mill will produce the desired particle size for optimal sorbent utilization.

In this trial, testing established a correlation between mill amps and particle size distribution; and optimization of a FCM (Fine grind Classifier Mill) operation was conducted by modifying the PLC controls to ensure the particle size would remain unchanged over a broad feed rate range, from 2,800 lb./hr. to 7,000 lb./hr. In an alternate operating method, the air classifier would change speed based upon the mill motor current, to maintain a constant amperage draw.

Process Description

An air classifier mill is an air-swept mill with an integrated dynamic classifier, for very precise particle sizing/narrow particle size distribution.

- Air is pulled into the mill chamber, from an upstream air-intake filter, often combined with a chiller coil.
- The product is pneumatically injected (using the conditioned process air, via a booster-blower) to the mill chamber.
- The mill disc with symmetric (flip- & turn-able) mill-blocs, is rotated with high tip-speed, impacting the

product against the rippled liner. The product breaks up both from mechanical impact and particle collision.

- The dynamic classifier rotates in the same direction as the mill-disc, but with its own independent variable drive.
- The air introduced to the mill, via the air-inlet and together with the product, must pass through the classifier leaving the mill – carrying the milled product.
- The classifier rotation applies a centrifugal force to the milled particles, slinging particles ‘still too large’ back to the grinding area of the mill, and the particle size is further reduced, before passing through the classifier.
- In precisely controlling the classifier speed, one can control the Particle Size Distribution (PSD) very narrowly – as is required in grinding Sodium Bicarbonate (SBC) to optimum PSD for dry sorbent injection (DSI) for acid gas mitigation.

Field Testing and control optimization

The air classifier control logic was modified by using a function generator based upon feed rate and mill amperage during test trials.

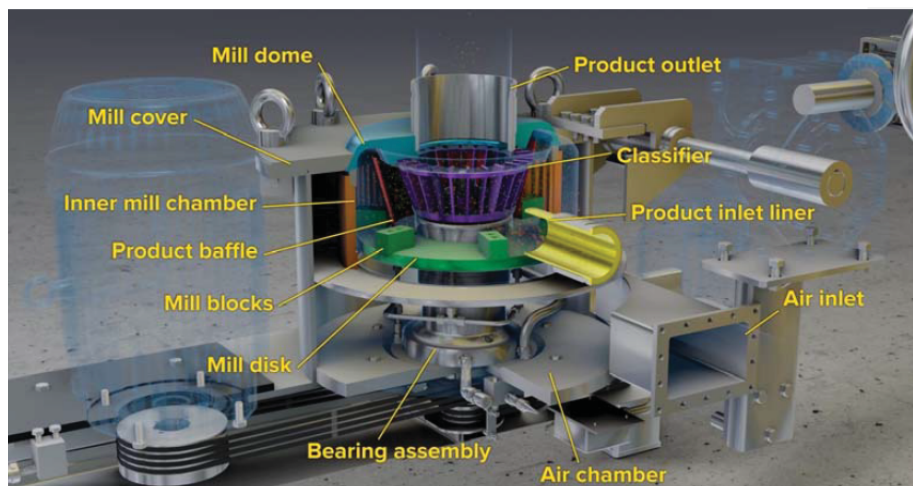


Figure 14: FCM Mill

Mill motor amperage desired value is also a function generated value based upon the feed rate.

- The classifier motor drives the classifier to keep material in the mill, by applying centrifugal force to particles.
- At low feed rate the classifier motor speed needs to be proportionally higher, to hold un-milled particles back.
- As the feed rate increases the air classifier can slow down, since there is more material to mill against itself.
- The amperage of the mill main motor will increase as the classifier speed increases, and more product is milled. The classifier speed adjustment from minimum to maximum is about a 2:1 ratio. There is also a limit to how low a feed rate can be, while still maintaining objective particle size as well as diminishing returns on a high feed rate. The mill will have to be sized appropriately for the desired feed rate range

Particle size distribution was determined using a Malvern Insitac inline particle analyzer during test runs. The Malvern Insitac analyses a sample every 20-30 seconds, averaging the PSD result over a set time (5-10 minutes) and repeats continuously.

Control Methods

Constant AMP control

In this control method, the classifier speed is adjusted, at any given capacity, from 3,000 lb/hr to 7,000 lb/hr to achieve optimum product particle fineness using a constant 150 Amp. ie) the product PSD becomes finer at lower feed rates. Using this method the PSD was D(90)- 18 micron at 3,000 lb/hr – D(90)-19 micron at 3,500 lb/hr up to D(90)- 24 micron at the max 7,000 lb/hr rate.

Constant Particle Size Distribution (PSD) control;

In this control method, the classifier speed is adjusted to maintain a predetermined optimum product particle size distribution (PSD), at any given capacity, from 3,000 lb/hr to 7,000 lb/hr, using less mill-amps at lower rates and higher mill-amps at high rates. The typical PSD set-point resulted in a PSD D(90) range of 23-25 micron, with 100 Amps at 2,800 lb/hr, 110 Amps at 3,500 lb/hr, 150 Amps at 7,000 lb/hr

SUMMARY

Using field gathered data, a function generator can be used to determine the optimal classifier speed at various feed rates and mill amperage to maintain a constant particle size distribution. In the range of feed rates tested, there was minimal change to particle size distribution. Compared to other mill-

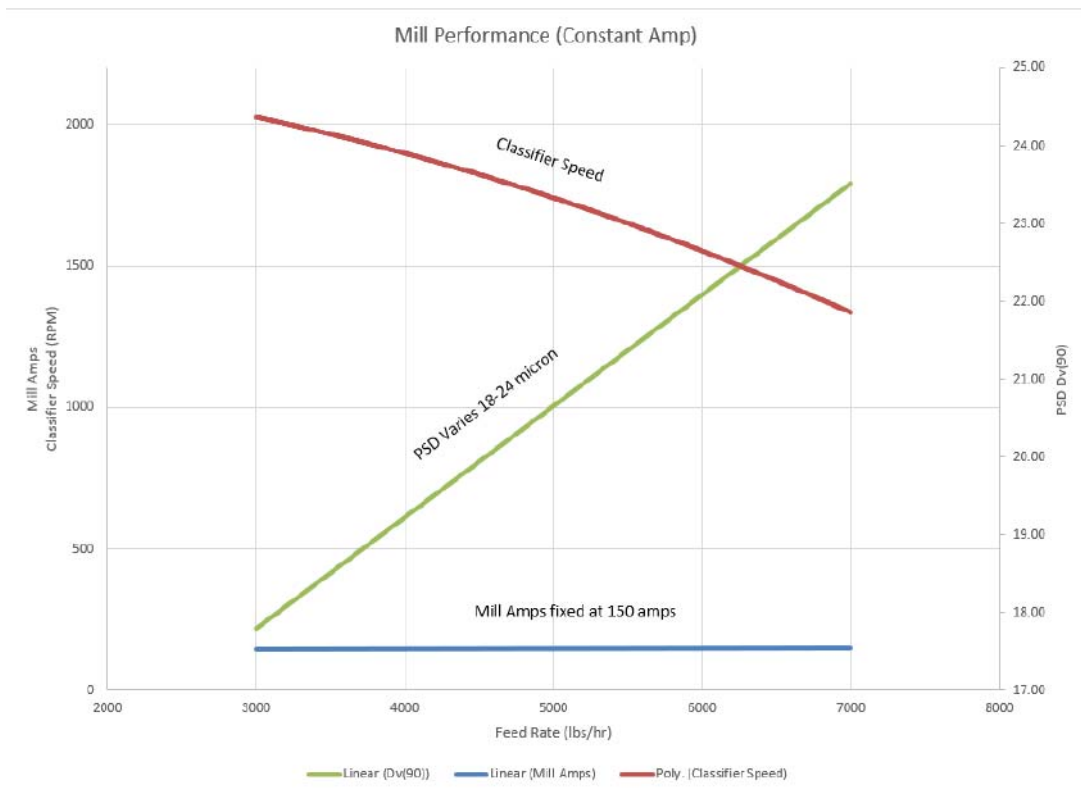
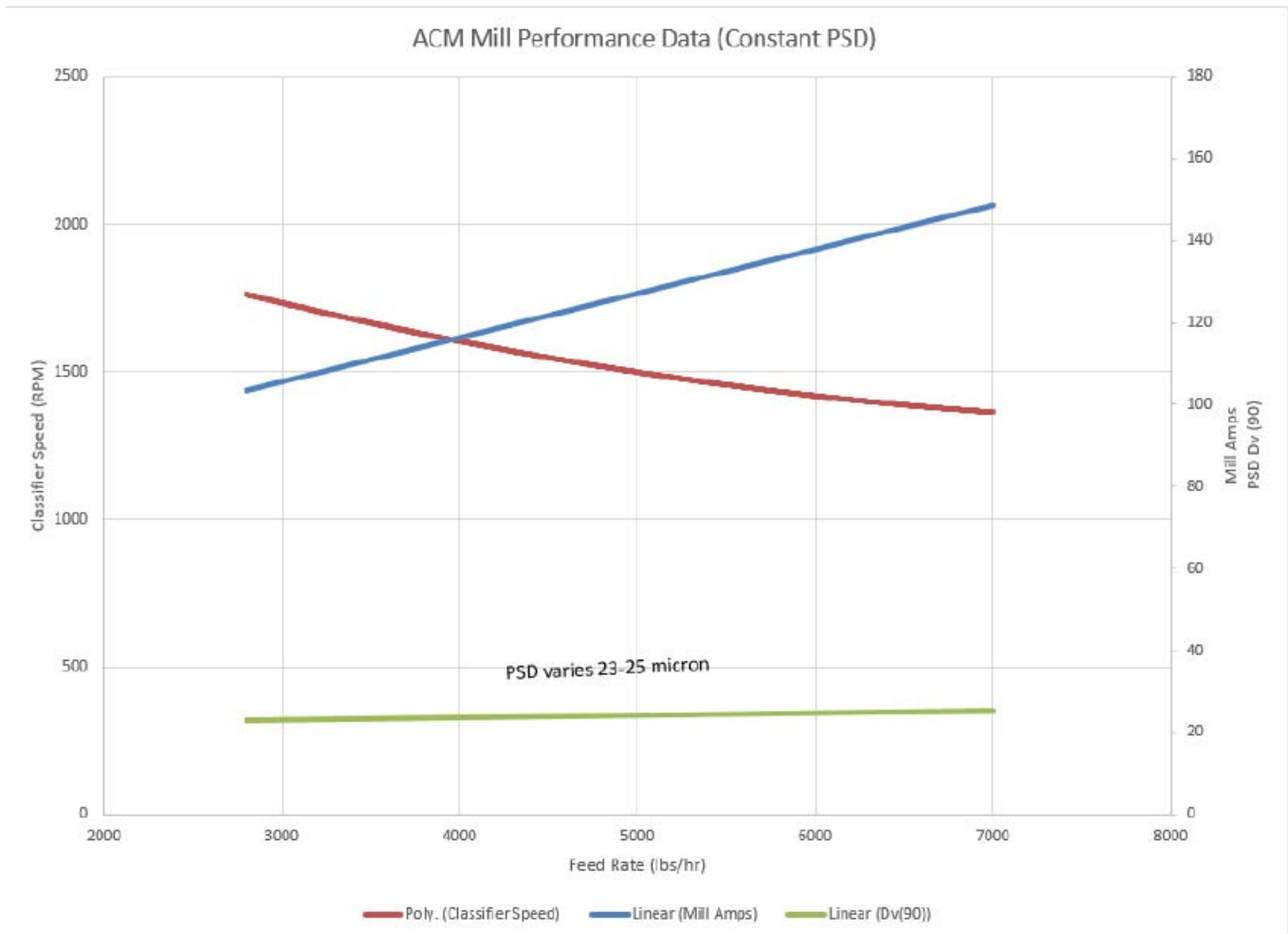


Figure 15: Mill Performance (constant Amp)

Figure 16: ACM Mill Performance Data (Constant PSD)



ing technologies the FCM mill is a high velocity impact mill, which rather rips the particles apart, and thereby opens up more surface area.

*For further information contact
Alan Heuser at alheuser@nol-tec.com*

BIOGRAPHY

Alan Heuer is an electrical engineer with a strong background in automation and controls. He is a graduate of Bemidji State University and has a B.S. in Physics. Alan joined Nol-Tec Systems in 2010. Alan may be reached at 651.780.8600 ext. 253, or by email at alheuser@nol-tec.com



Tomas Johansson has been a product manager and chief process engineer for Sturtevant FCM Air classifier mill systems since 2006. Tomas is a graduate of Lund University with a background in Mechanical & Process Engineering, Economy and Business. Tomas plans to retire in 2020. Tomas may be reached at (815)919-4652, or by email at tjohansson@sturtevantinc.com

Process Sampling and Chemical Analyses for Cost-effective Emissions Control on Coal Units

Written by Cassandra Hutson, AECOM Process Technologies

ABSTRACT

Most coal-fired electric generating units (EGU) today are operating in unfamiliar territory. With low-cost natural gas and increased generation from renewable energy, utilities are constantly challenged to respond to the market through leaner, more flexible operation and bare bones operating costs while simultaneously maintaining regulatory compliance. This article summarizes how use of process sampling and chemical analysis can be effective tools in identifying and assessing lower cost operational options for coal fired EGUs .

INTRODUCTION

In today's economy, coal-fired power plants must compete against lower prices of power derived from natural gas. In addition, new Effluent Limitation Guidelines will soon impose stringent limits on wastewater discharged from most wet flue gas desulfurization (FGD) systems on coal-fired units. Installing or upgrading air quality control system (AQCS) components and wastewater treatment (WWT) systems requires significant capital expenditures and generally increases plant operating and maintenance (O&M) expenses. Remaining competitive while continuing to meet environmental regulations is challenging. Economics have forced some formerly base-loaded units to switch to cycling load operation, which brings new O&M challenges. In an effort to lower capital and operating costs, many plants are seeking lower cost fuels, reagents and/or additives, and some have tightened wet FGD water balances to reduce the amount of water requiring treatment.

While the FGD system primarily serves to remove sulfur dioxide (SO₂) from the flue gas, it also often offers the significant co-benefit of mercury (Hg) removal. Because the FGD system is at the tail end of the AQCS, any fluctuations in upstream operations (e.g., coal type, unit load, boiler operations, O&M of other AQCS components) can negatively impact FGD operation and performance and therefore, SO₂ removal and/or Hg removal, and environmental compliance.

A wet FGD system is, at its core, a chemical process. FGD sample collection and analyses are required to best understand the impacts of upstream changes and how to adjust operations to account for those changes. Chemistry changes

can affect many facets of the FGD process including limestone reactivity and utilization, sulfite oxidation rate, mercury phase partitioning in the absorber slurry and re-emission, and many others. While many utilities routinely monitor selected components in FGD chemistry (such as chlorides to control wastewater purge rates), additional analyses can be used on an ad hoc basis to investigate specific issues. Higher than normal SO₂ or Hg emissions, as an example, can have multiple root causes. Only by evaluation of sampling and analytical data can the cause be uncovered before emission limits are exceeded and/or money is spent treating symptoms instead of the root cause. The chemical analysis of samples can also help identify lower-cost alternatives to fuels, reagents and additives.

Two examples of illustrating the effectiveness of chemical analysis follow below. These examples highlight considerations for O&M cost reduction by changing limestone sources and troubleshooting a mercury emission problem. These represent two of many potential opportunities to use chemical sampling and analysis for problem resolution and/or cost reduction efforts.

LIMESTONE SELECTION

Limestone reagent is a significant operating cost for coal-fired power plants with scrubbed units. Lower-cost sources can be utilized to make the unit more competitive. While a new reagent source may cost less per ton on a delivered basis, or even on a delivered cost per ton of calcium carbonate (CaCO₃), some unexpected adverse effects are possible. These could include:

- Decreased limestone reactivity (slow dissolution),
- Reduced SO₂ removal,
- Increased reagent grinding costs,
- Impacts on FGD mercury capture and/or downstream wastewater treatment, and
- Decreased byproduct dewatering characteristics.

Limestone purity (% CaCO₃), while an important consideration, is not the sole indicator of how a limestone will perform in an FGD system. There are several other key factors that should be investigated through physical and chemical analyses, such as grindability, total magnesium concentra-

tion, dolomite concentration, reactivity, utilization of the reactive component under simulated FGD conditions, and concentrations of trace metal impurities. These results can be used to estimate plant reagent costs and to indicate potential balance-of-plant impacts.

Determining the grindability of a limestone, such as by Bond Work Index (BWI) measurements, can indicate how much energy will be required to obtain an optimal limestone particle size. Harder limestones (higher BWI) typically require longer grinding times per ton to reach a desired particle size. Figure 17 depicts a limestone grinding operation. Both the grindability and the reactive content of the limestone should be considered when comparing limestones for grinding O&M costs. Differences in BWI will indicate relative grinding energy per ton, while differences in reactive content will indicate the relative quantity that will have to be ground to achieve the same removal performance.

Dolomite is a mineral that contains equimolar concentrations of calcium and magnesium carbonate, $\text{CaCO}_3 \bullet \text{MgCO}_3$, and is relatively insoluble in the typical wet FGD pH range. The presence of dolomite further underscores the pitfalls associated with reliance only on CaCO_3 purity data when determining the performance of a potential limestone, as the CaCO_3 present in dolomite will not likely be available to support SO_2 removal. Limestone utilization is directly impacted by dolomite present in the limestone, since utilization is a measure of how much calcium carbonate is converted to calcium sulfate at a selected pH and the calcium carbonate in dolomite will not be readily available. The availability of the reactive (non-dolomite) CaCO_3 is also affected by the presence of dolomite, which at higher concentrations decreases reactive limestone dissolution rates. The percentage of dolomite present in a limestone cannot be determined from a simple elemental analysis of a candidate limestone.

Mineral compound identification techniques such as X-ray diffraction, or bench-scale testing under FGD conditions is required to determine what fraction of the total magnesium in a limestone is present as soluble magnesium carbonate versus in dolomite.

Trace metal concentrations in limestone can affect wet FGD operations, wastewater composition, and byproduct gypsum handling. Aluminum can form aluminum-fluoride complexes that can greatly slow limestone dissolution, decrease pH, and decrease SO_2 removal. Arsenic and selenium are potential concerns for downstream wastewater treatment. Copper, manganese, and molybdenum are oxidation catalysts which can promote higher slurry ORP and potentially increase mercury re-emissions. Manganese can cause scaling and underdeposit corrosion of some absorber alloys. Finally, anecdotal information has identified strontium, and in some cases iron, as potential crystal growth modifiers which can lead to smaller overall gypsum particle size and/or less desirable crystal shapes and therefore result in a gypsum cake that is challenging to dewater.

In summary, the CaCO_3 purity of a limestone should not be the sole factor driving a utility to change reagent feeds to obtain a cost benefit. A full analysis of the limestone will help steer the utility to a more informed decision, possibly preventing what may turn out to be a costly mistake.

MERCURY EMISSIONS

Many wet FGD systems are used as a key component of the unit’s mercury control strategy. They generally absorb oxidized mercury (Hg^{2+}) very efficiently. Elemental mercury (Hg^0) is relatively insoluble and very little is absorbed in an FGD system. The net removal of mercury across an FGD system is sometimes limited by a phenomenon called “re-emission,” where oxidized mercury that has been absorbed



Figure 17: Limestone Grinding Operations

reacts with other species, predominantly sulfite ion (SO_3^{2-}), and gets chemically reduced to elemental mercury. The insoluble elemental mercury formed is released back into the flue gas and emitted out the stack.

Sometimes mercury emissions excursions occur in systems using wet FGD as the primary Hg control device. The cause of the intermittently higher emissions is not immediately evident. Often the first assumption is that the increased mercury emissions are due to re-emission from the FGD system, and expensive re-emission control additives are dosed into the absorber slurry. While re-emission could be occurring, one or more of many other possible factors could be the cause including:

- Increased coal mercury content (lb/TBtu);
- Lower coal chlorine content;
- Lower unburned carbon content in the fly ash;
- Decreased Selective Catalytic Reduction (SCR) catalyst activity; or
- Reduced mercury control by powdered activated carbon (PAC) upstream of the FGD system

Analysis of flue gas, liquid, and/or solid samples from representative points throughout the AQCS can help determine the cause of the higher stack mercury emissions and thus the most cost-effective approach to resolving the issue.

One possibility is that the coal quality has changed due to a different source or to variations at the mine. Analysis of the coal for mercury and chloride concentrations and heat content allows a comparison to the previous coal fired. For ex-

ample, if there is lower chloride content but similar mercury content, there will likely be a lower percentage of oxidized mercury present in the flue gas, thus a lower percentage that can be absorbed across the FGD system. Lower mercury oxidation percentages may also be caused by decreases in SCR catalyst activity. With activity loss, higher ammonia-to- NO_x ratios may be required to maintain NO_x emission compliance, and greater coverage of the catalyst active surfaces with ammonia adversely affects mercury oxidation across the catalysts.

If boiler performance changes such that the unburned carbon in the fly ash is reduced, mercury adsorption will decrease and mercury concentrations in the flue gas entering the FGD system will increase. Analysis of the fly ash for loss on ignition (LOI) or carbon concentration, and for mercury concentrations, can provide information on changes which may have led to increased mercury emissions.

Since many upstream factors can adversely affect the ability of the FGD system to control stack mercury emissions, speciated mercury concentration measurements at the FGD inlet can indicate whether total mercury concentrations and/or the percentage of elemental mercury have increased. Such increases may explain an increase in stack mercury emissions and lead to the investigation to upstream changes. Speciated mercury measurements are also key to confirming re-emission across the FGD system. Coal and fly ash analyses are generally less expensive than flue gas sampling, so these are often done first.

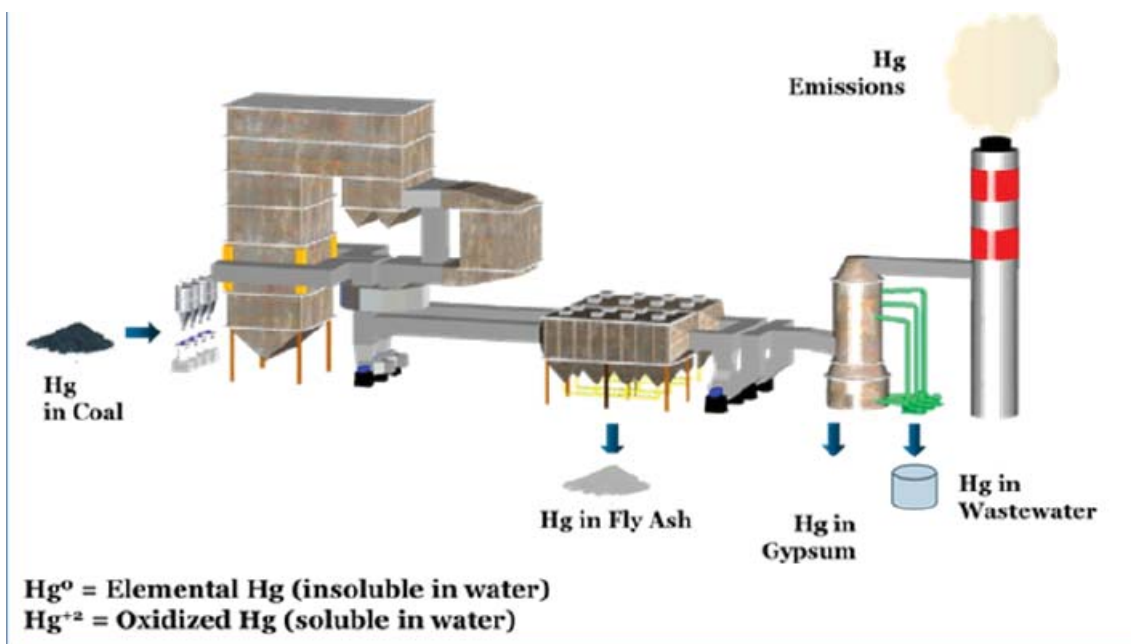


Figure 18: Fate of Hg through Coal Fired EGU

Mercury re-emissions from the FGD system may be caused by over oxidizing conditions in the FGD absorber. Over-oxidizing conditions can often result if the unit is operated at low load for extended periods and the forced oxidation air rate is not decreased to account for the lower SO₂ input to the FGD system. Over-oxidizing conditions are typically characterized by relatively high concentrations of mercury in the absorber liquor as compared to the absorber solids and absorber slurry ORP values above ~250-300 mV. Figure 19 shows the percent of mercury in absorber liquor vs ORP for different types of systems. In highly oxidizing conditions, mercury can be released from the solid phase into the liquor phase. A large concentration of oxidized mercury in the liquor (e.g., 10 µg/L or greater) is an indicator that re-emission could be occurring. If the dissolved mercury concentration is very low (<1 µg/L) re-emission is less likely to be occurring. Routine or ad hoc measurements for liquor-phase mercury concentrations can help diagnose suspected incidents of re-emission.

Comparing current absorber ORP results to past results might indicate an increase that correlates with the higher stack mercury emissions. However, comparing ORP results from plant instrumentation is not always sufficient. ORP probes require periodic calibration checks and maintenance to read correctly and to rapidly respond to process changes, so ensuring that the probes are checked, cleaned and calibrated regularly is very important. Comparison measurements with lab instrumentation should be conducted to

confirm on-line instrument results when diagnosing mercury emission increases.

The best way to confirm whether re-emission is occurring is to measure speciated mercury concentrations in the inlet FGD flue gas. The stack mercury concentration should be measured as well if the unit is not equipped with a continuous emissions monitor (CEM). Downstream of an efficient FGD absorber that does not bypass any flue gas, the stack mercury should be nearly 100% in the elemental form. If the FGD inlet elemental mercury concentration is relatively close to the stack total mercury concentration, then significant re-emission is not indicated. However, if the stack total mercury concentration is considerably greater than the FGD inlet flue gas elemental mercury concentration, this confirms re-emission.

In summary, while mercury re-emission is always a possibility when stack mercury emissions are observed to increase downstream of a wet scrubber, there are many other possible causes of the increase. A well-planned sampling and analysis effort can identify the root cause of the increase and identify the appropriate corrective action. This can ensure that mercury emission compliance can be restored, and potentially avoid injecting expensive sorbents or additives to treat the symptom, not the cause.

CONCLUSIONS

As coal-fired power plants strive to comply with existing en-

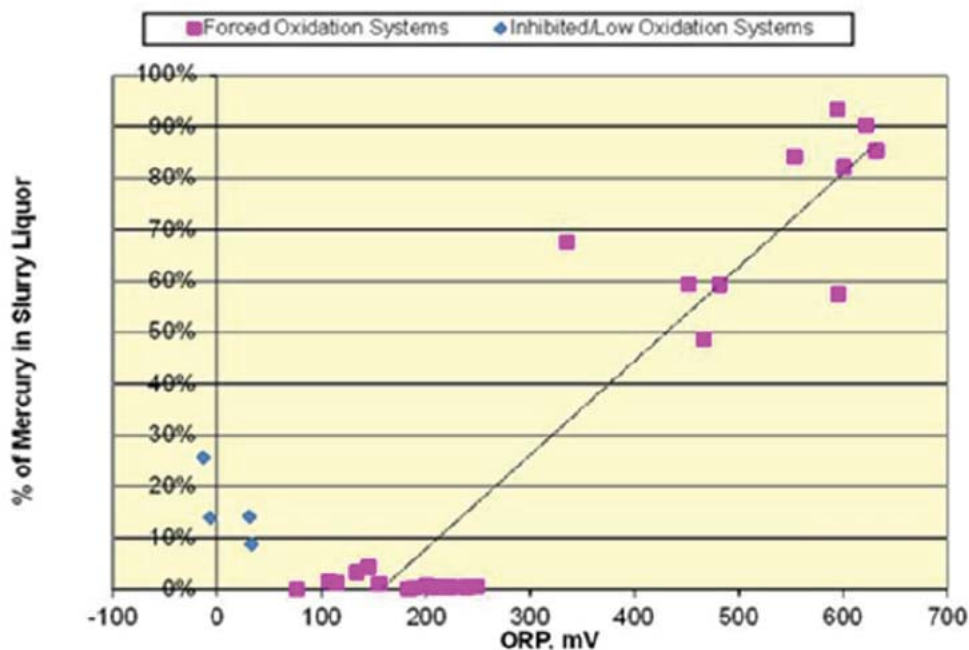


Figure 19: Percent of Mercury in FGD Absorber Liquor vs ORP

environmental regulations and lower costs to remain viable, the collection and analysis of samples for chemical constituent concentrations is a valuable tool to support decision-making. For now, traditional sample collection and analysis in a plant or off-site laboratory remains the best approach to understand the chemical makeup of coal, limestone, fly ash, and FGD slurries, and to determine possible impacts on FGD operations. In the future, online monitors for a variety of key parameters such as dissolved mercury in absorber slurry could support more timely process control. Some of these monitors already exist and are being proven in FGD slurry matrices.

*For further information
contact Cassandra Hutson at*

BIOGRAPHY



Cassandra is a Senior Chemist for AECOM's Process Technologies Organization (PTO) with 24 years of experience working as an analytical chemist and project manager. At AECOM, her work focuses on air and water pollution control technologies for the power industry. Many of her projects involve researching flue gas desulfurization (FGD) absorber chemistry and specifically trace metals partitioning between the liquor, solid,

and gas phases. She has developed sampling and analytical plans and overseen sample collection and analysis activities for numerous sites.

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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.

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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.

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1500 Toney Drive
Huntsville, AL 35802 USA
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LUNGSTROM
13785 Research Blvd.
Austin, TX 78760 USA
email: steven.kosler@ljungstrom.com

Allen Kephart,
President
CleanAir Engineering
110 Technology Dr.,
Pittsburgh, PA 15275
Email: akephart@cleanair.com

Mike Mattes
CEO
Cormetech
304 Linwood Rd, Ste. 102,
Kings Mountain, NC 28086 USA
Email: m.mattes@steagscrtech.com

Mike Allen,
Senior Sales Manager
CLARCOR Industril Air
11501 Outlook St., Ste. 100,
Overland Park, KS 66211 USA
Email: mike.allen@clarcor.com

Wesley McKenzie,
VP Technology
Southern Environmental, Inc.
6690 West Nine Mile Rd., Pensacola, FL 32526
Email: wmckenzie@sei-group.com

Jerry VanDerWerff
Director of Business Development
Nol-Tec Systems
425 Apollo Drive
Uno Lakes, MN 55014 USA
Email: JerryVanDerWerff@nol-tec.com

Curt Biehn,
Technical Director
Mississippi Lime
3870 S. Lindbergh Blvd.,
St. Louis, MO 63127
Email: crbiehn@mlc.com

Paul Ford,
President
Redkoh Industries
300 Valley Road,
Hillsborough, NJ 08844 USA
Email: paul.ford@redkoh.com

Nate White,
Director, Air Emission Control
Umicore Catalyst USA
5510 Morris Hunt Dr.,
Fort Mill, SC 29708 USA
Email: Nathan.White@am.umicore.com

Kevin McDonough,
VP Sales & Marketing
United Conveyor Corporation
2100 Norman Drive West
Waukegan, IL 60085 USA
Email: kevinmcdonough@unitedconveyor.com

John Cochran,
President
IBIDEN CERAM Environmental
7304 W. 130th St., Ste 140,
Overland Park, KS 66213
Email: john.cochran@ceram-usa.com

Claire Schmit
Principal Process Engineer
AECOM
9400 Ambergien Blvd.,
Austin, TX 78729 USA
Email: claire.schmit@aecom.com

Greg Hebler,
Principle Engineer
Golder
75170 Peachtree Road
Atlanta, GA 30341 USA
Email: ghebler@golder.com

Bill Kennedy
Senior Principal
Stantec
2127 Ayrnsley Town Blvd. Ste 300
Charlotte, NC 28273
Email: bill.kennedy@stantec.com

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