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A Bi-Annual Newsletter Sponsored by the WPCA Winter - 2016

Executive Summary

U.S. EPA OTM-036: "Wet" Particle Sizing Test Method Promises Lower $PM_{2.5}$ Reportable Emissions

By Jim Guenthoer, Clean Air Engineering

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Full Story….

A High Reactivity Hydrated Lime For Improved SO_2 Capture

By Richard Zhang, Mississippi Lime

High performing hydrated lime products for Dry Sorbent Injection (DSI) applications offer Utility and Industrial operators cost-effective sorbent options, simple feed systems, and improved fly ash characteristics when compared to other DSI alternatives. Mississippi Lime has developed a new generation High Reactivity Hydrated Lime product HRH-64 for improved SO_2 capture in DSI applications.

Full Story….

ModuPower™ MPX Reduces Particulate Matter Emissions in Cement Plant ESP Application

By Elavarasu Jayakumar, Schenck Process India

Schenck Process India Pvt Ltd (SPG) supplied ModuPower™MPX power supplies for a clinker cooler ESP at a 5,500 TPD capacity cement plant where additional changes to the ESP were required to meet new the government PM emission limit regulation of 30mg/Nm^3. After MPX commissioning, plant startup, and tuning of the MPX & rapper controls, the PM emission were confirmed to be well below target.

Full Story….

World-Class Technology for the Newest Waste-to-Energy Plant in the United States Palm Beach Renewable Energy Facility No. 2

By J.B. Kitto, Jr., M.D. Fick, and L.A. Hiner - The Babcock & Wilcox Company; W.J. Arvan - Palm Beach Resource Recovery Corporation; R.H. Schauer - Solid Waste Authority of Palm Beach County

On July 18, 2015, Palm Beach Renewable Energy Facility No. 2 began commercial operation. The plant is owned by the Solid Waste Authority (SWA) of Palm Beach County and is the first greenfield waste-to energy (WTE) facility to come online in North America in 20 years. The facility incorporates the latest advanced technologies from the U.S. and Europe to provide the cleanest and most advanced efficient WTE facility of its kind in the world today — generating renewable energy and reducing net greenhouse emissions.

Full Story….

Reducing the Cost of Mercury Control with Fuel Additives

By Connie Senior and Sharon Sjostrom, ADA-ES, Inc.

Addition of halogens to increase mercury oxidation in coal combustion flue gas is often included as part of a plant's mercury control strategy. Selection of the halogen species to add, and whether the halogen is added to the coal or as a treated activated carbon can have very longer-term balance-of-plant operational risk implications for the plant, and costs.

Full Story….

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Executive Summary (cont.)

Oxidation Air Rate Optimization and Control for Enhanced MATS Mercury Compliance

Written by Gary Blythe, PE, and Mandi Richardson, AECOM Process Technologies Organization

Since the implementation of EPA's Mercury and Air Toxics Standards (MATS), many LSFO wet FGD systems now serve as mercury control as well as SO_2 removal devices. To serve both purposes efficiently, the forced oxidation air rate should now be optimized to strike a compromise between these objectives. Modifications to the oxidation air system may be required to provide adequate turndown and control capability to implement this optimization. Although these revisions, if needed, will require a modest capital investment to implement, they can greatly reduce or even eliminate ongoing O&M expenses for re-emission additives, and in some cases can provide a modest reduction in FGD power consumption.

Full Story….

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WORLDWIDE POLLUTION CONTROL ASSOCIATION

U.S. EPA OTM-036: "Wet" Particle Sizing Test Method Promises Lower $PM_{2.5}$ Reportable Emissions

Written by Jim Guenthoer, Clean Air Engineering

INTRODUCTION

Although the National Ambient Air Quality Standard (NAAQS) for particulate matter 2.5 microns and smaller ($PM_{2.5}$) was promulgated in 1997 and last updated in 2012, a method for measuring filterable $PM_{2.5}$ emissions from regulated sources with wet stack gas streams has yet to be promulgated by the U.S. EPA. Current U.S. EPA guidance for sources with entrained water droplets is to measure total filterable particulate matter (FPM) by U.S. EPA Method 5 and report all FPM as $PM_{2.5}$, which as later discussed creates a positive bias in the reported results.

This issue will become more problematic for sources complying with $PM_{2.5}$ emission limits with future revisions to the NAAQS standards and the increased focus on fine particulate emissions as outlined in the U.S. EPA's recently published Environmental Justice Strategic Plan for 2016-2020 and employment of Citizen Science to enable community engagement in the measurement of local air pollution through the use of affordable, easy-to-use analytical tools.

The good news is several industry groups have been working on this issue and submitted a testing method which the U.S. EPA has posted on the Emission Monitoring Center (EMC) website as Other Test Method – 036: Method for the Determination of Filterable $PM_{2.5}$ Emissions from Moisture Saturated and/or Droplet-laden Stationary Source Gas Streams (Constant Sampling Rate Procedure).

It should be noted that Other Test Methods (OTM) have not been promulgated by the Federal Rulemaking process and the use of these methods may be considered for compliance demonstrations of federally enforceable state or local programs with appropriate regulatory approval.

BACKGROUND

In 2011 an article was published in the WPCA newsletter titled "An "Old School" Approach Modernized for Today's Air Pollution Control Challenges --Particle Size Distribution Testing in "Wet" Gas Streams Using In-Situ Cascade Impactors." This article presented research and development work that had been done by Clean Air Engineering (CleanAir) performing particle size distribution (PSD) testing in moisture saturated (wet) and / or droplet laden gas streams from stationary sources. Typically on the outlet of wet scrubbers. This application was not and is not in widespread use in the testing community.

The crux of that PSD testing was the use of a precutter mounted on the inlet to the cascade impactor that removed the larger water drops that otherwise would have shattered and flooded the impactor. As noted in the previous article, this precutter was originally designed by Dr. Joe McCain of Southern Research Institute (SoRI) and a modified design was specifically developed for wet sources by Dr. McCain for the California Air Resources Board (CARB) during the creation of CARB Method 501.

The original SoRI precutter was later modified by Pollution Control Systems Corporation (PCSC) and this version was developed by Mr. Jim Guenthoer in cooperation with the late Mr. Don Russell of Russell Engineering, Inc. to increase the capture capacity and add a liner that significantly increased the efficacy of sampling in wet gas streams.

THE ISSUE

Industries with wet process gas streams that have a $PM_{2.5}$ emissions standard have up to now been forced to use U.S. EPA Method 5 to determine the filterable $PM_{2.5}$ fraction of their emissions rather than EPA Method

201A whose employment of size specific cyclones removes a portion of the total filterable catch from inclusion with the $PM_{2.5}$ filterable sample. U.S. EPA 5 was mandated because of the possibility that $PM_{2.5}$ particulate matter might be entrained within larger water drops that would be removed in the greater than $PM_{2.5}$ sample fraction, yielding a lower than accurate $PM_{2.5}$ emission value.

However it is also known that by using U.S. EPA Method 5 particulate matter that is in fact larger than $PM_{2.5}$ is counted in with the filterable $PM_{2.5}$ sample fraction, biasing the emissions data high which can be a major fraction of the emissions counted towards the 10 tons of $PM_{2.5}$ per year prevention of significant deterioration (PSD) significance level. This bias can also cause errors in dispersion modeling used to demonstrate compliance with $PM_{2.5}$ national ambient air quality standards (NAAQS).

Dia. um	Cum.% -	Cum.Conc mg/dncm
0.100	0.02	1.43E-02
0.126	0.14	8.44E-02
0.158	0.77	4.63E-01
0.200	3.69	2.23E+00
0.251	12.18	7.37E+00
0.316	23.91	1.45E+01
0.398	37.30	2.26E+01
0.501	53.27	3.22E+01
0.631	66.75	4.04E+01
0.794	74.24	4.49E+01
1.000	77.93	4.72E+01
1.259	80.88	4.89E+01
1.585	83.66	5.06E+01
1.995	85.94	5.20E+01
2.512	**87.64**	**5.30E+01**
3.162	88.90	5.38E+01
3.981	89.86	5.44E+01
5.012	90.68	5.49E+01
6.310	91.53	5.54E+01
7.943	92.56	5.60E+01
10.000	93.80	5.68E+01
12.589	95.12	5.76E+01
15.849	96.41	5.83E+01
19.953	97.53	5.90E+01
25.119	98.43	5.96E+01
31.623	99.08	6.00E+01
39.811	99.51	6.02E+01
50.119	99.76	6.04E+01
63.096	99.90	6.04E+01
79.433	99.96	6.05E+01
100.000	99.99	6.05E+01

FIGURE 1

Dia. um	Cum.%	Cum.Conc. mg/dncm
0.010	0.02	1.17E-02
0.013	0.06	3.45E-02
0.016	0.16	8.93E-02
0.020	0.37	2.05E-01
0.025	0.76	4.22E-01
0.032	1.42	7.81E-01
0.040	2.39	1.32E+00
0.050	3.70	2.04E+00
0.063	5.31	2.93E+00
0.079	7.11	3.92E+00
0.100	8.94	4.93E+00
0.126	10.64	5.87E+00
0.158	12.24	6.75E+00
0.200	13.95	7.70E+00
0.251	16.74	9.24E+00
0.316	23.12	1.28E+01
0.398	30.94	1.71E+01
0.501	35.17	1.94E+01
0.631	36.90	2.04E+01
0.794	38.45	2.12E+01
1.000	40.33	2.23E+01
1.259	42.20	2.33E+01
1.585	46.10	2.54E+01
1.995	55.36	3.05E+01
2.512	**69.85**	**3.85E+01**
3.162	82.75	4.57E+01
3.981	89.90	4.96E+01
5.012	92.70	5.12E+01
6.310	93.80	5.18E+01
7.943	94.49	5.21E+01
10.000	95.35	5.26E+01
12.589	96.30	5.31E+01
15.849	97.25	5.37E+01
19.953	98.10	5.41E+01
25.119	98.78	5.45E+01
31.623	99.28	5.48E+01
39.811	99.61	5.50E+01
50.119	99.81	5.51E+01
63.096	99.92	5.51E+01
79.433	99.97	5.52E+01
100.000	99.99	5.52E+01

FIGURE 2

CleanAir's wet particle sizing work using cascade impactors, while not the main focus of the projects where it was used, provided insight into what the $PM_{2.5}$ contribution was coming out of for example venturi scrubbers on coal fired boilers and seawater flue gas desulphurization (SWFGD) units following electrostatic precipitators (ESP) on heavy fuel oil (HFO) fired boilers. Figure 1 (on page 2) is the result of doing a spline fit with the impactor data from a test run on a wet stack from a scrubber equipped coal fired boiler.

Performing a Method 5 test on this stack would over report the $PM_{2.5}$ emissions by 12.4%. Looking at the same type of data from the absorber outlet on the HFO fired plant provides the cumulative size relative weight percentages shown in Figure 2 (on page 2).

Doing a Method 5 test on this source for $PM_{2.5}$ would mean over reporting by approximately 30%.

A PATH FORWARD

The American Petroleum Institute (API) recognized this problem several years ago, especially as pertaining to fluidized catalytic cracking units (FCCU) which are most frequently equipped with scrubbers. The API, with more recent contributions from the National Council for Air and Stream Improvement (NCASI), has funded research and the development of a test method meant to address performing $PM_{2.5}$ testing on a wet source.

The method marries a precutter head like those used with cascade impactors with a $PM_{2.5}$ cyclone and backup filter from Method 201A. The cyclone and filter are out of stack in a chamber heated to 320 ±25 ºF. The probe coming from the precutter head to the cyclone inlet is also heated to 320 ±25ºF. The precutter head is run in-stack at stack temperature. What this means is that regardless of the stack temperature (wet stacks being typically from 130 – 180 ºF), the cyclone is always essentially at the same temperature so you can ensure you are getting an accurate cut diameter within the 2.25 – 2.75 µm acceptable range every run.

The precutter has a nominal 50% cut diameter (D50) of 12 µm. This has been deemed sufficient to remove any larger than $PM_{2.5}$ containing water drops while passing through the material that needs to be sampled for an accurate $PM_{2.5}$ determination of the source. The method is essentially the CARB 501 supplemental method for wet stacks designed by Dr. McCain that CleanAir has been using for their research work only with a heated $PM_{2.5}$ cyclone substituted for the cascade impactor. A schematic of the method is shown in Figure 3.

You will note in the sketch that the U.S. EPA Method 202 sampling train is referenced. Like the use of U.S.EPA 201A/202 together OTM-036 is designed to be used in combination with U.S. EPA Method 202 so that both filterable and condensable $PM_{2.5}$ will be captured.

CONCLUSION

On April 30, 2015 API and NCASI in a joint letter to EPA requested that this method be advanced to Other Test Method (OTM) status. By granting OTM status the method may be

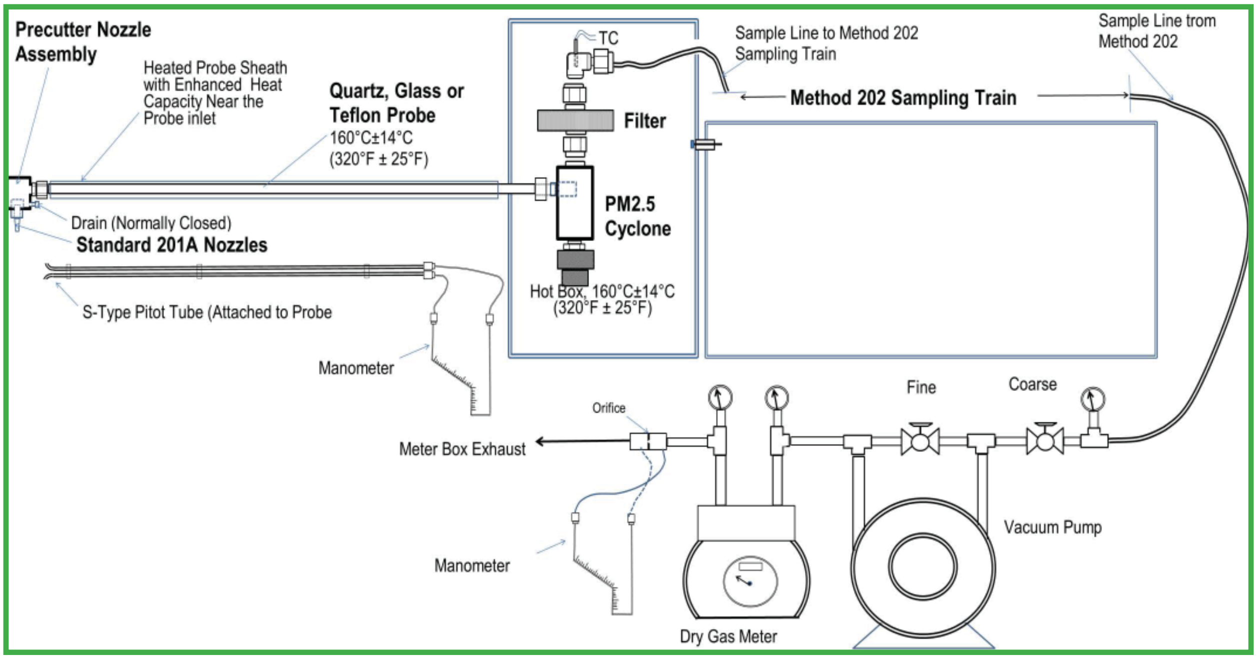

FIGURE 3: *A schematic of the method*

considered by permitting authorities for use on their regulated sources. This would allow wider use of the method and the generation of a larger data set to evaluate the method moving forward. On April 11, 2016 EPA issued the method as OTM-036. Currently there is limited demonstrated expertise in this method or any type of wet particle sizing since these type of methods have not previously been used for compliance determinations.

CleanAir believes with more R&D and field testing to further develop this method, sources with entrained water droplets will have an alternative test approach to help to minimize $PM_{2.5}$ emission over reporting. It will be very interesting to see the evolution of this method as it applied across a wide range of industries facing these ever increasing regulatory challenges.

For further information contact
Jim Guenthoer at jguenthoer@cleanair.com

BIOGRAPHY

Mr. Guenthoer has almost 40 years of experience in the field of air emissions testing and consulting. Prior to joining Clean Air Engineering, he worked at several other engineering consulting firms as well as air pollution control and source testing equipment manufacturers. While at those firms his roles included project management and field testing, as well as design, manufacture, technical service, and sales of in-situ cascade impactor particle sizing devices. While at one firm he was involved with research and development studies of novel particulate control technologies using enhanced electrostatics. He earned his BS Degree from Juniata College and an M.S.E. in Environmental Engineering from the University of Washington.

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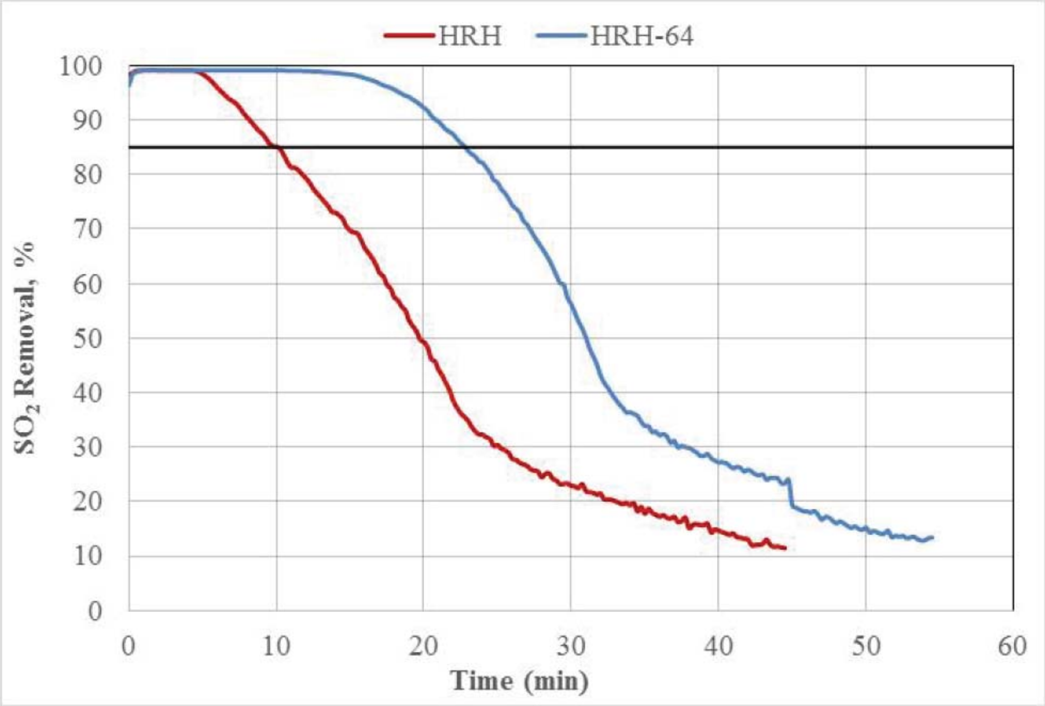
A High Reactivity Hydrated Lime For Improved SO_2 Capture

Written by Richard Zhang, Mississippi Lime

ABSTRACT

High performing hydrated lime products for Dry Sorbent Injection (DSI) applications offer Utility and Industrial operators cost-effective sorbent options, simple feed systems, and improved fly ash characteristics when compared to other DSI alternatives. Mississippi Lime has developed a new generation of High Reactivity Hydrated Lime (HRH), HRH-64, for improved SO_2 capture. HRH-64 has been tested in laboratory, pilot plant and full scale evaluations. A high SO_2 removal rate of 85% was achieved using HRH-64 during a full scale demonstration at a power plant equipped with a baghouse. Demonstration at another Utility indicated that the sorbent usage with HRH-64 is about 20% less than a reference enhanced hydrated lime. Additionally, HRH-64 has been tested at a cement plant, with improved removal rates of both SO_2 and HCl compared to the rates when using HRH.

FIGURE 4: Breakthrough Curves of HRH-64 vs. HRH (300 ppm SO_2 /0 ppm HCl)



INTRODUCTION

Coal-fired boilers face increasing regulatory demands on acid gas emission controls. EPA's Mercury & Air Toxics Standards (MATS) Rule, SO_2 NAAQS, and Regional Haze Rule set more stringent removal requirements on sulfur dioxide (SO_2), hydrochloric acid (HCl), mercury (Hg) and particulate matter (PM). Conventional control technologies such as wet FGD and dry scrubbers (SDA or CDS) provide high SO_2 removal[1], but they require a very high capital investment. Dry Sorbent Injection (DSI) technology has the advantage of simple process configuration and, more importantly, low capital cost compared to wet and dry scrubbers.[2]

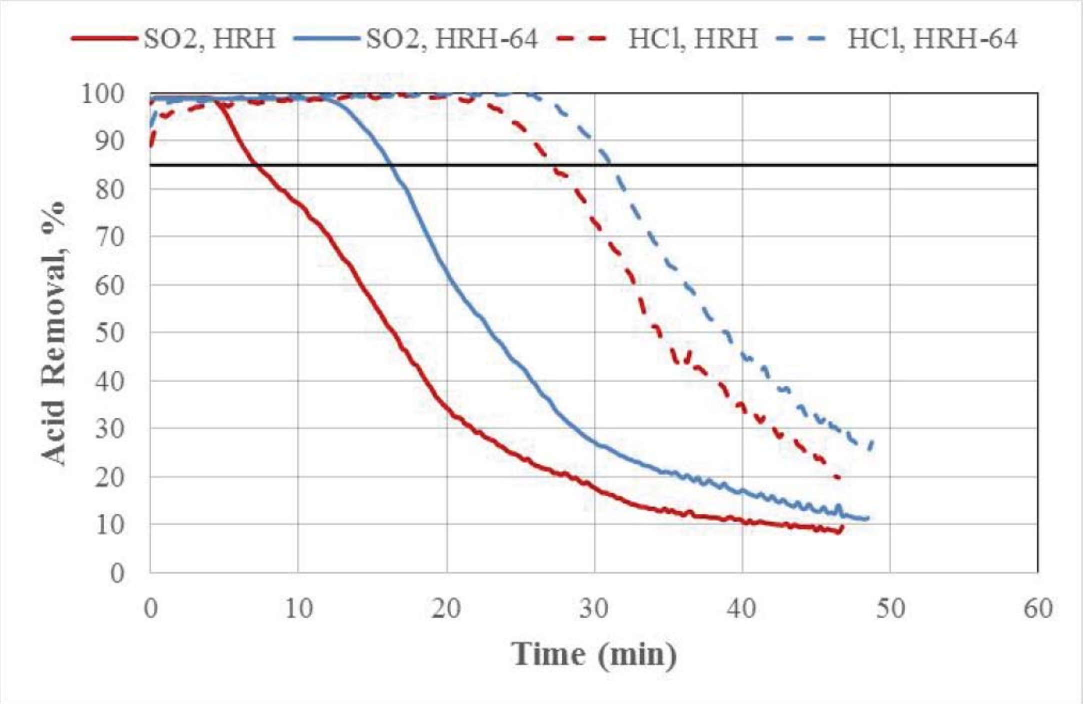
In a DSI system, a fine powder of alkali sorbent is directly injected into the duct after the combustion chamber and upstream of a particulate collecting device such as a fabric filter baghouse (BH) or an electrostatic precipitator (ESP). Calcium-based sorbents are generally preferred options for acid gas mitigation due to availability of raw materials, cost effectiveness and ash friendly properties. DSI of sodium based sorbents (trona and sodium bicarbonate) has been considered for SO_2 emission reduction.[3] However, there are concerns with the ash quality and its toxic metals leaching propensity when the sodium-based sorbents are used. EPA Effluent Limitation Guidelines (ELGs) set stringent limits on toxic metals including arsenic (As) and selenium (Se). A significant research study on Trona has been conducted for both Class F and Class C fly ashes by Missouri University of Science and Technology. The study concluded that Trona and sodium carbonate introduced significant soluble Na-compounds to the ash, resulting in more leaching of anionic elements (Se, As, V and Mo).[4,5] In contrast, reduced leaching of Se and As from high Ca fly ash is due to calcium precipitation and formation of low solubility compounds.[6]

Over the past ten years, hydrated lime DSI has been successfully adopted by the Utility industry for mitigation of acid gases such as sulfur trioxide (SO_3) and hydrogen chloride (HCl). These acidic species, generated during combustion and (where applicable) through oxidation across a SCR, contribute to air heater fouling, corrosion, and stack blue plume. While many industrial grades of hydrated lime products have been tested in environmental applications[7], the most effective hydrated lime sorbents for DSI are those that have high (>20 m^2/g) BET surface area and high available hydrate content.[8] By 2013, Mississippi Lime had developed High Reactivity Hydrated Lime (HRH) for mitigation of SO_3 and HCl in challenging situations such as high removal rate or short residence time applications.[9,10] Evaluations, from bench-scale to pilot and full scale testing, demonstrated that HRH performs significantly better than the FGT (Flue Gas Treatment) grade of hydrated lime, and, by extension, standard grade of hydrate lime. HRH provides additional benefits compared to FGT such as ultra-low pollutant (SO_3/HCl) removal, rapid removal of SO_3 prior to the air preheater (APH), reduced sorbent usage for marginal ESPs, and lower annual cost to supply.[9,10]

Dry sorbent injection of HRH has been tested for SO_2 mitigation, with removal rates of up to 50-60%. However, in many applications a higher removal rate with improved utilization is required. Higher SO_2 removals may be achieved using HRH in conjunction with modifications aimed at improved sorbent distribution or flue gas coverage. Furthermore, enhanced SO_2 removal may be achieved by injecting sorbent at optimum temperature locations. Sorbent injection temperature has a significant impact on SO_2 removal. Two optimum temperature windows for calcium hydroxide have been recognized, i.e. 2400-2000 °F in the furnace and 1200-800 °F upstream of air preheater.[11] Furnace injection of calcium-based sorbents has been extensively studied, and sintering is a key limiting factor for calcium hydroxide at furnace temperatures. Economizer injection of hydrated lime at a temperature of approximately 1000°F has been evaluated in a pilot scale study, but further validation in the field is necessary. DSI of hydrated lime has been typically conducted at pre/post-air preheater locations. Pre-air preheater DSI is aimed at higher temperatures (~700°F) near the optimum temperature window. Post-air preheater DSI, such as at the baghouse inlet (~300°F), can also provide good SO_2 capture. In addition, further improvement in SO_2 removal may be achieved with humidification by approaching saturation temperature.[11-13]

Mississippi Lime has recently developed a new product, HRH-64, that is specifically designed for SO_2 capture. HRH-64 is a new generation of high reactivity hydrated lime that provides high reaction capacity as well as fast reaction rate in reference to sulfur dioxide. This paper presents the evaluation results of HRH-64 on SO_2 capture from laboratory to pilot plant to full scale studies.

FIGURE 5: Breakthrough Curves of HRH-64 vs. HRH (300 ppm SO_2 /30 ppm HCl)



LABORATORY FIXED-BED STUDY

Experimental

Samples of hydrated lime (HRH-64 and HRH) were tested for SO_2/HCl capture using a benchscale micro-reactor at Southern Research Institute in Birmingham AL. The tests were conducted with a fixed-bed mixture of sand and hydrated lime in the reactor at a constant temperature of 650ºF. A stream of simulated flue gas containing the desired concentrations of SO_2, HCl, O_2, NO, CO_2 and N_2 was introduced from the inlet of the reactor at a constant total system flow rate of 8 L/min. The test gas passed through the sorbent prior to exiting the reactor. The concentration of SO_2 was 300 ppm. Two HCl concentrations, 0 or 30 ppm were used. The other gas compositions were 3% O_2, 8% H_2O, 10% CO_2, 250 ppm NO and N_2 the balance. The sorbent loading was 0.6 g. The test gas from outlet of the reactor was monitored with FTIR (Fourier transform infrared spectroscopy).

Results

The acid gas removal as a function of time is represented by the breakthrough curves. The breakthrough curves obtained for HRH-64 and HRH are shown in Figures 4 and 5, for 0 and 30 ppm HCl, respectively. Figure 4 (on page 5) is adequate to represent the comparison of HRH-64 and HRH for PRB coal that generally has a low concentration HCl. With 30 ppm HCl in the flue gas, the breakthrough has occurred at a much later time for HCl than SO_2 as shown in Figure 5 (on page 6): approximately 26 min. for HCl & 12 min. for SO_2 with HRH-64 and approximately 20 min. for HCl & 4 min. for SO_2 with HRH. This indicates that, compared to SO_2, HCl is more reactive with hydrated lime under the experimental conditions of this study. It is noteworthy that HRH-64 exhibited a superior performance in capturing SO_2 regardless of HCl presence in the simulated flue gas.

The initial breakthrough time, time to achieve 85% removal, and the total percent acid removal during the test duration (45 min) for HRH and HRH-64 are summarized in Figure 6 and 7 for inlet gas concentration of 300 ppm SO_2 only and 300 ppm SO_2 plus 30 ppm HCl, respectively. The total acid gas removal (SO_2 or HCl) is calculated by using the area under the breakthrough curves.

PILOT PLANT EVALUATION

Experimental

A pilot plant evaluation of HRH-64 for SO_2 capture was conducted at Babcock & Wilcox Research Center's Small Boiler Simulator II (SBS-II) in Barberton Ohio. The SBS-II facility includes a 6 MMBtu/hr furnace and convection pass, fuel subsystems, acid gas injection unit, pulse jet fabric filter (PJFF) baghouse, and gas analyzers. During the testing program the furnace was fueled with the natural gas. The heated air was then humidified and spiked with the various concentrations of SO_2 and HCl to generate a simulated flue gas. The nominal gas flow rate was 6700 lb/hr (2200 acfm). The acid gas injection location was at the trim heater outlet. Because the testing program was focused on the capture of SO_2 with hydrated lime DSI, the ratios of HCl to SO_2 were

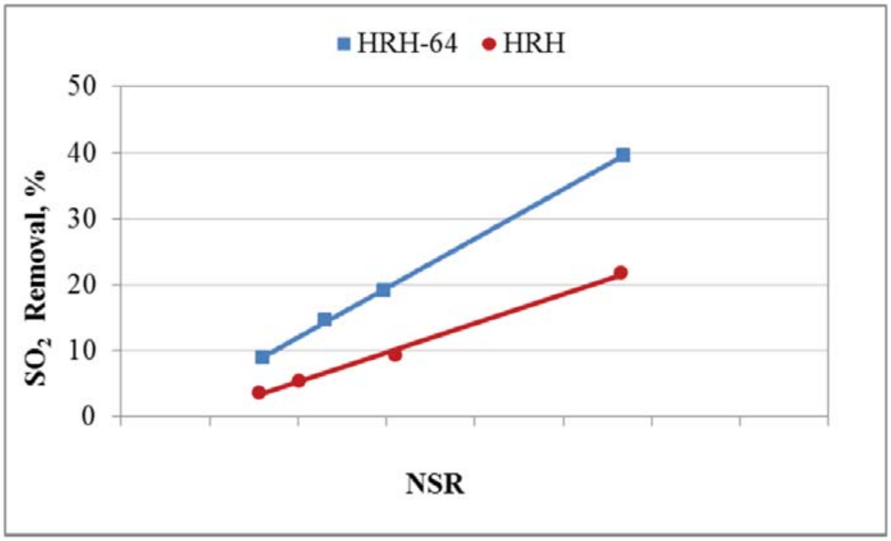
FIGURE 6: Initial Breakthrough Time and Total SO_2 Removal (300 ppm SO_2 / 0 ppm HCl)

Sorbent	Initial Breakthrough Time	Time to Achieve 85%Removal	Total SO_2 Removal @ 45 min
HRH	4 min	10 min	49%
HRH-64	13 min	23 min	72%

FIGURE 7: Initial Breakthrough Time and Total Removal (300 ppm SO_2 / 30 ppm HCl)

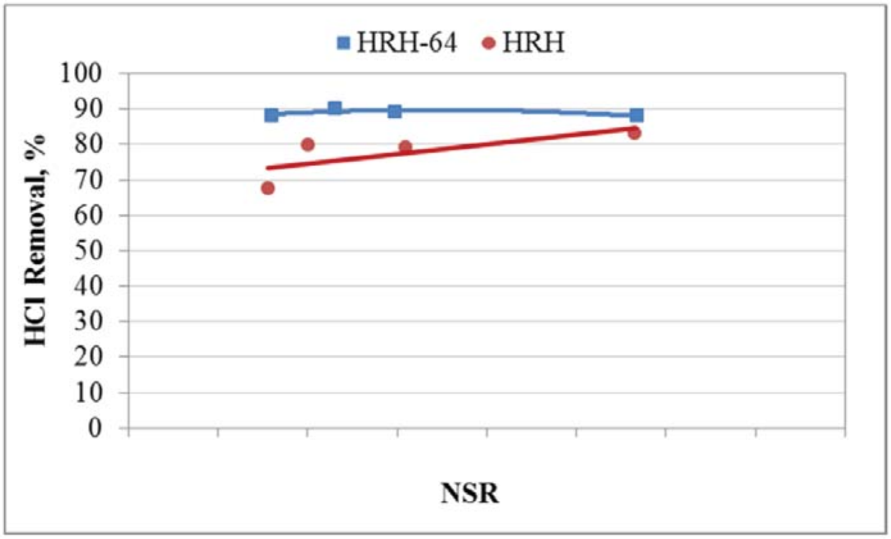
Sorbent	SO_2			HCl		
	Initial Breakthrough Time	Time to Achieve 85% Removal	Total SO_2 Removal @ 45 min	Initial Breakthrough Time	Time to Achieve 85% Removal	Total HCl Removal @45 min
HRH	4 min	7 min	43%	20 min	27 min	79%
HRH-64	12 min	16 min	58%	26 min	31 min	85%

FIGURE 8: In-flight Capture of SO_2 for HRH-64 vs. HRH at HCl:SO_2 of 0.25



kept low at 0 & 0.25. The SO_2 concentrations were 100 ppm & 400 ppm, and the HCl concentrations were 0, 25 ppm & 100 ppm. Steam was injected downstream of the acid gas injection point. However, the moisture content in the gas stream was limited to about 4.9% due to system constraints. Hydrated lime samples (either HRH-64 or HRH) were injected approximately 10 feet downstream of the steam injection point where the DSI temperature was ~320°F. Sorbent in-flight residence time to the baghouse was about 3.6 seconds. The baghouse was designed with a short cycle time of 30 min. The fly ash was collected fairly frequently and the acid gas captured at the fabric filter baghouse was relatively small compared to the typical full scale unit, which was expected due to the use of manufactured flue gas as opposed to coal combustion. In-flight removal rates were used for comparing the relative performance of the two sorbents.

FIGURE 9: In-flight Capture of HCl for HRH-64 vs. HRH at HCl:SO_2 of 0.25



Results

The results of in-flight SO_2 removal rate versus normalized stoichiometric ratio (NSR) for HRH-64 and HRH are shown in Figure 8. HRH-64 performs significantly better in SO_2 removal than HRH. While experimental conditions such as moisture content and injection temperature are less than ideal for high SO_2 removal with hydrate, results strongly confirm those from the SRI benchscale fixed-bed testing: HRH-64 has improved performance compared to HRH.

Figure 9 shows in-flight removal of HCl versus normalized stoichiometric ratio for HRH-64 and HRH. HCl removal is considerably higher than SO_2 removal at the treatment rates tested. HRH-64 performs somewhat better in HCl removal than HRH although this difference is not profound as that for SO_2 capture.

FULL SCALE EVALUATIONS

Following the laboratory and pilot plant testing, HRH-64 was further evaluated at full scale combustion units. Four case studies are presented below: Case Studies A, B, C from Utility boilers and Case Study D from a cement plant.

Case Study A: Hydrated Lime Comparison at a Small Utility Boiler

This Utility desires to reduce SO_2 emissions from one of their units in order to meet the requirements of the EPA Regional Haze Rule. The boiler burns PRB coal and typically operates at loads of less than 200 MW. The unit is configured with an economizer, air preheaters, and electrostatic precipitators for collecting particulate. The coal has a typical sulfur content of ~0.3% with low chlorine content. A SO_2 removal rate of 50-80% or better is desired and hydrated lime DSI is under consideration as a low capital cost solution for mitigating SO_2.

To evaluate the DSI option, hydrated lime DSI was conducted at the inlet of APH. The flue gas had a temperature of about 700°F at the injection location, and the moisture content was about 12% vol/vol. The injection rate during this test was varied to develop parametric information with target stoichiometric ratios. No issues with the ESP operations were observed at injection rates of up to about 2,000 lb/hr. Figure 10 summarizes the results of SO_2 removal versus the normalized stoichiometric ratio (NSR) of hydrated lime to SO_2 for three types of hydrated lime: HRH-64, HRH, and FGT. Considerably higher SO_2 removal is observed with HRH-64 compared to HRH and FGT, particularly for high NSR. HRH overall outperforms FGT. Based on this information it was concluded that it would require significantly less HRH-64 to achieve the SO_2 removal target (70-80%).

Case Study B: HRH-64 at a Small Boiler with Baghouse

This unit has a typical full load capacity of less than 200 MW. With tighter regulation on Particulate Matter (PM) emission, the utility has recently replaced the ESPs with the new fabric filter pulse-jet baghouse. HRH-64 was evaluated with injection at the air pre-heater outlet roughly 40-50 feet from the inlet of the baghouse. The temperatures at the injection points were approximately 340°F for B duct and 300°F for A duct, with B duct having about 10% more flue gas flow than the A duct. The baghouse outlet temperature was approximately 300ºF and the flue gas moisture content was ~10% vol/vol. The coal used during the first three days of testing had an average sulfur content of 0.4% as received and chlorine content was less than 0.01%.

Hydrated lime was fed with a DSI system equipped with a calibrated volumetric screw conveyer. When the system was in automatic mode, a continuous emissions monitor detected the stack SO_2 outlet value and adjusted the speed of the feed screw conveyer. The utility established an internal control target of 130 ppm SO_2 maximum emissions. During the current testing program, the manual control on the feed was used and this allowed SO_2 variations with different hydrate feed rates.

FIGURE 10: SO_2 Removal vs. NSR for HRH-64, HRH & FGT Hydrated Limes

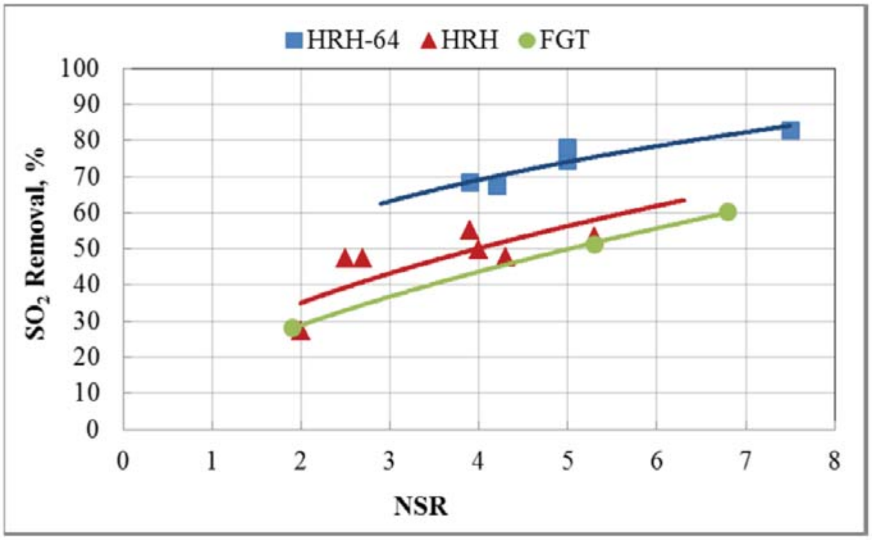


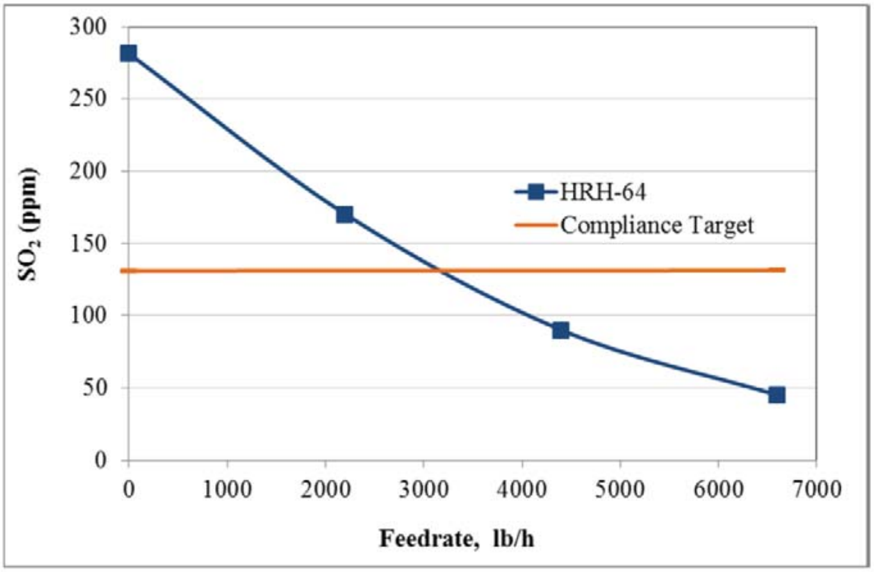
Figure 11 (on page 10) shows SO_2 emissions versus feed rate of HRH-64 for Case Study B. The concentration of SO_2 emissions decreased as the hydrate feed rate increased. At a feed rate of 4,400 lb/hr, SO_2 emissions came down to about 90 ppm, well below the target of 130 ppm. This indicates that it is possible to use significantly less sorbent with HRH-64 and meet regulatory compliance. Figure 12 (on page 10) shows the SO_2 removal rate versus the normalized stoichiometric ratio (NSR) for HRH-64. SO_2 removal rates ranging from 40% to 85% were obtained with NSR of 1.9 to 5.5. A SO_2 removal rate of higher than 85% is attainable with HRH-64 at a higher injection rate. This was not pursued during the test since we already met the compliance target at about 55% removal. It is noteworthy that over 80% SO_2 removal has been achieved at a relatively "low" NSR of 5.5, compared to that previously reported for hydrated lime DSI in the literature.[14] The potential for high SO_2 removal with HRH-64 could give utilities more flexibility in choosing lower cost higher sulfur coal.

It was important to assess balance-of-plant impacts such as BH pressure drop and PM. Throughout the test, baghouse pressure drop remained at ~ 0.16 psi. The utility also examined PM emissions and concluded that the dry sorbent injection of HRH-64 did not have negative impact on PM emissions.

Case Study C: HRH-64 vs. Reference Enhanced Hydrate at a 150 MW Unit with Baghouse

HRH-64 was evaluated for SO_2 removal performance against a reference enhanced hydrated lime in a 150 MW Utility boiler equipped with a baghouse for PM control. The unit burns a blend of Nymex/Colorado coal. This unit injects hydrated lime prior to the air preheater to reduce SO_2 emissions below 0.8 lb/mmBTU. Both high load and low load conditions were evaluated. Figure 13 (on page 11) shows the comparative hydrated lime feed rates used in order to maintain SO_2 emissions. The average feed rate of

FIGURE 11: SO_2 Outlet (ppm) vs. Feed rate of HRH-64

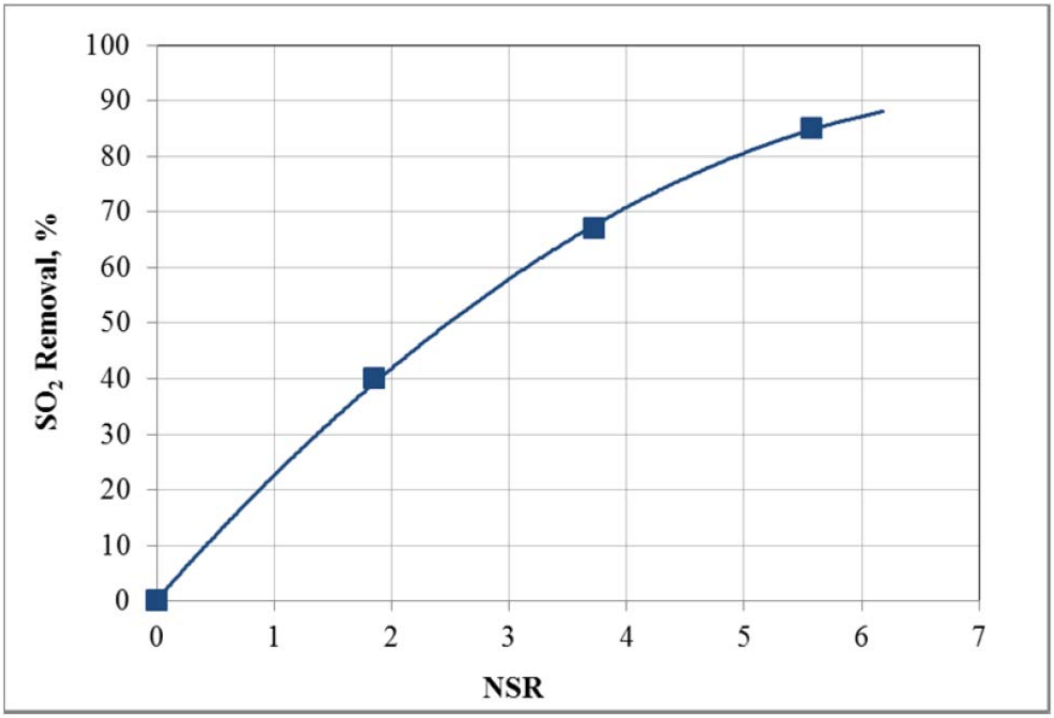


HRH-64 (e.g. 5,100 lb/hr) was about 20% lower than that of the other enhanced hydrated lime.

Case Study D: HRH-64 vs. HRH at a Cement Plant

HRH-64 and HRH were evaluated at a cement plant using a temporary DSI system. The cement plant needs to meet future acid gas regulations for both HCl and SO_2. The Cement MACT requires that plants comply with an HCl emission limit of 3 ppmvd @7% O_2 (30 operating day rolling average) by Sept. 2016. For this plant, that means that over 60% removal of HCl is required with hydrated lime DSI. In addition, this cement plant will have to meet future SO_2 regulations to be decided by the state.

FIGURE 12: SO_2 Removal vs. NSR for HRH-64



The test program compared two sorbents (HRH-64 and RH) at different injection locations (Kiln ID Fan, Feed Bin and Baghouse Inlet) with raw mill on/off conditions. The raw mill is used to grind the limestone raw materials prior to feeding to the cement kiln, and emissions are higher when the raw mill is off. The flue gas temperatures at different DSI locations were 680°F, 545°F, and 350°F for feed bin, kiln ID fan and baghouse inlet, respectively. The HCl was monitored by NDIR (Nondispersive infrared) and the SO_2 was monitored by CEMS. Both SO_2 and HCl removal were best when injecting hydrate at the baghouse inlet.

The results with hydrated lime DSI at the baghouse inlet (with raw mill off) for HRH-64 and HRH are shown in Figures 14 and 15 (on page 12) for HCl and SO_2, respectively. Higher removal rates of HCl than SO_2 are generally observed at the same hydrate feed rate. HRH-64 outperforms HRH in both HCl and SO_2 removal. To achieve 60% HCl reduction, less sorbent is required for HRH-64 than HRH (500 lb/hr vs. 1,000 lb/hr). At a feed rate of 1,000 lb/hr, higher than 50% removal in SO_2 is obtained with HRH-64, while the SO_2 removal with HRH is under 40%.

SUMMARY

Mississippi Lime has developed a new generation High Reactivity Hydrated Lime product HRH-64 for improved SO_2 capture in DSI applications. HRH-64 has been evaluated from laboratory to pilot plant to full scale flue gas systems. A full scale evaluation of HRH-64 at a power plant equipped with ESP confirms that HRH-64 performs significantly better in SO_2 removal compared to the first generation HRH and the FGT grade of hydrated lime. A significantly lower DSI feedrate of HRH-64 is required to meet compliance target. No issues with the ESP have been observed at injection rates of up to about 2,000 lb/hr.

A full scale demonstration of HRH-64 at a power plant equipped with baghouse has shown that a high SO_2 removal rate of 85% is achieved with a NSR of 5.5. This sorbent to acid ratio is relatively "low" compared to that previously reported for hydrated lime DSI in the literature. The high removal rate can allow the utility meet the stringent compliance limit in SO_2. The effectiveness of HRH-64 on SO_2 mitigation has been demonstrated at another utility also equipped with baghouse. The results have indicated that the sorbent usage with HRH-64 is about 20% less than that of a reference enhanced hydrated lime. Dry sorbent injection of HRH-64 has a minimal effect on the baghouse pressure drop and no negative impact on PM emission.

HRH-64 has been evaluated in a cement plant for meeting Cement MACT on HCl and the state emission requirement on SO_2. HRH-64 has outperformed HRH in SO_2 removal as well as HCl removal. HRH-64 is a proven solution to HCl Cement MACT with added benefit of superior SO_2 capture.

FIGURE 13: Comparative Hydrated Lime Feed Rates to Maintain SO_2 Emissions

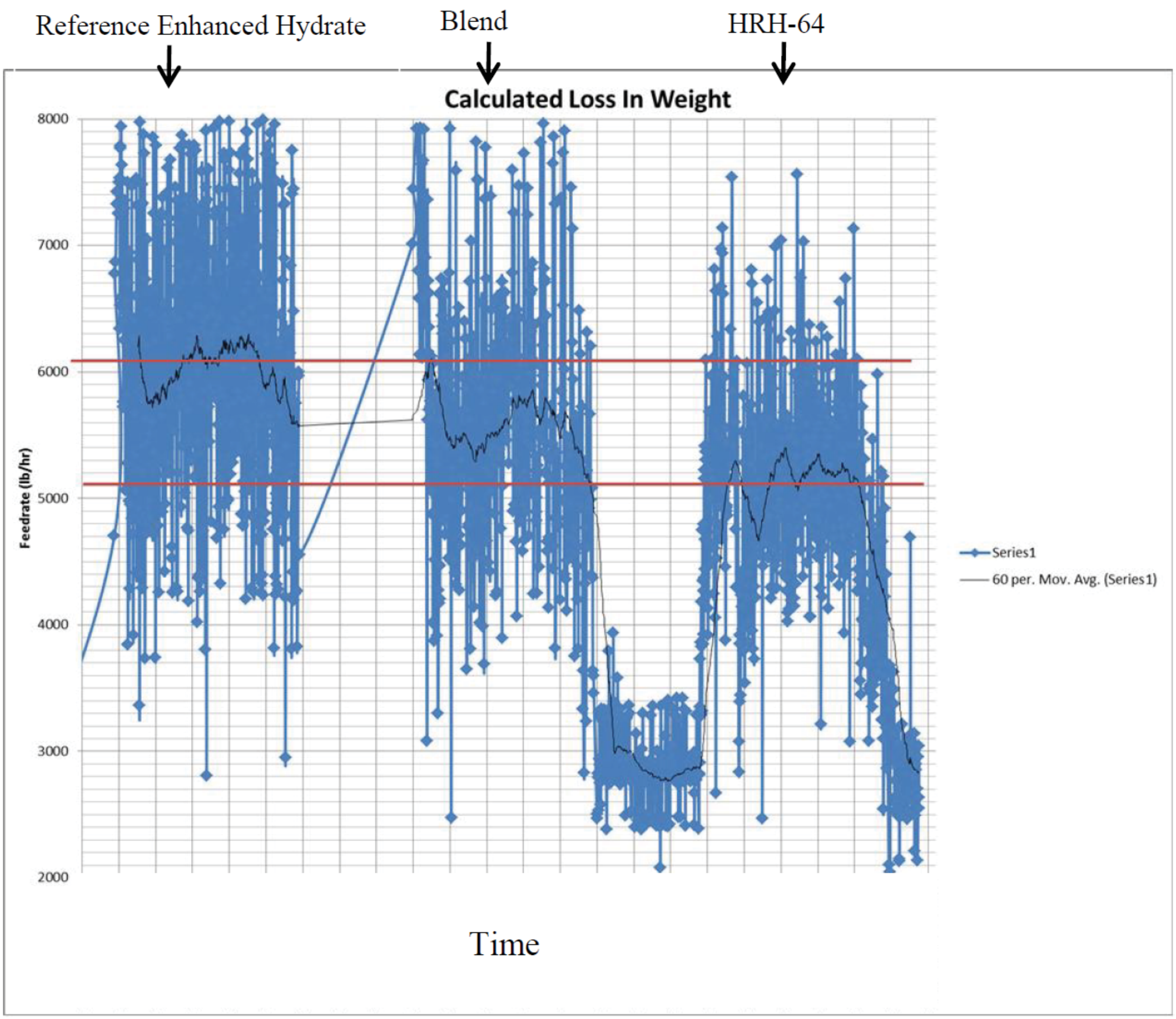


FIGURE 14: HCl Removal vs. Hydrate Feed Rate for HRH-64 and HRH

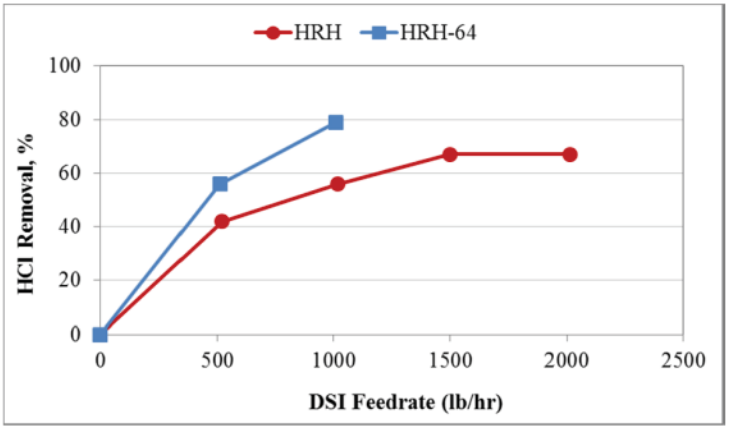


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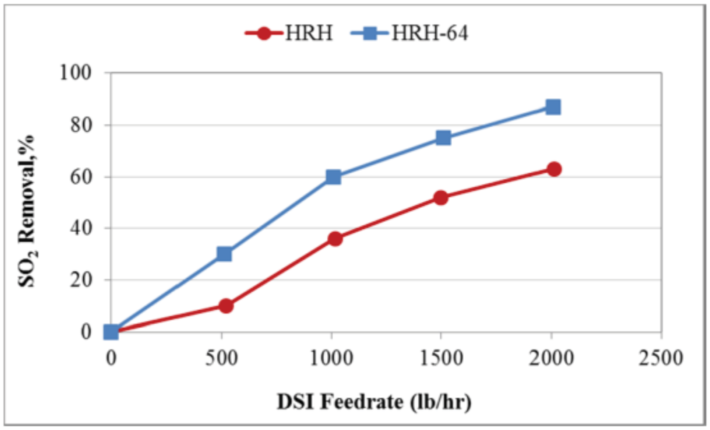
FIGURE 15: SO_2 Removal vs. Hydrate Feed Rate for HRH-64 and HRH



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ModuPower™ MPX Reduces Particulate Matter Emissions in Cement Plant ESP Application

Written by Elavarasu Jayakumar, Schenck Process India

Schenck Process India Pvt Ltd (SPG) supplied ModuPower™ MPX power supplies for a clinker cooler ESP at a 5,500 TPD capacity cement plant located in Srinagar, Yanagandla, Banaganapalle Village & Mandal, Kurnool, Andhra Pradesh. To control PM (Particulate Matter) emissions, the clinker cooler was originally equipped with a 4 field Thermax Electrostatic Precipitator (ESP) energized by conventional power supplies (TRSET).

The ESP was originally designed for a gas flow rate of 519,400 Am^3/hr, maximum inlet dust concentration of 22,000 mg/Nm^3, and outlet emission of 50 mg/Nm^3. The original design collection efficiency is 99.77%. While the plant was able to meet 48.9 mg/Nm^3, additional changes to the ESP were required to meet new the government PM emission limit regulation of 30mg/Nm^3.

My Home Industries (MHIPL) initially tried to meet the emission regulations by replacing conventional TRSETs with 3 phase TRSETs in all 4 fields. However after installation of the 3 phase TRSETs, the PM emissions remained at 43.89 mg/Nm^3, well above the level expected by MHIPL. The 3 phase TRSETs also created sparking issues in each field causing poor performance and excessive damage inside the ESP. The MHIPL then reinstalled the conventional TRSETs while searching for alternate solutions.

FIGURE 16: MHIPL Sree Jayajothi Cements Limited clinker cooler ESP with 4 fields - side view

FIGURE 17: 2 x 60 kW ModuPower™ MPX cabinets mounted remotely in control room. 100kV rated HV cable used to connect MPX to ESP.

MHIPL contacted SPG in January 2016 to discuss potential solutions to meet the government emission regulations. SPG was able to utilize their process expertise to provide the customer with performance estimates for a variety of scenarios. The confidence generated by this analysis prompted the customer to quickly exercise the proposed solution to lower the PM emission rate.

MHIPL decided to perform a trial run by replacing conventional TRSETs with MPX in only the first 2 fields out of 4 fields to get confidence about the MPX product and evaluate performance at steady state operation. For this scenario, SPG calculated and guaranteed an emission reduction from 48.9 mg/Nm^3 to 40 mg/Nm^3.

The complete scope of the project consisted of replacing (2) of (4) conventional TRSETs with (2) 60 kW MPX, replacing existing ESP ground switches, and equipment to remotely install the MPX cabinets 50 meters from the ESP using HV cable.

Comprehensive field service support was provided by SPG throughout the duration of the project which included a pre-

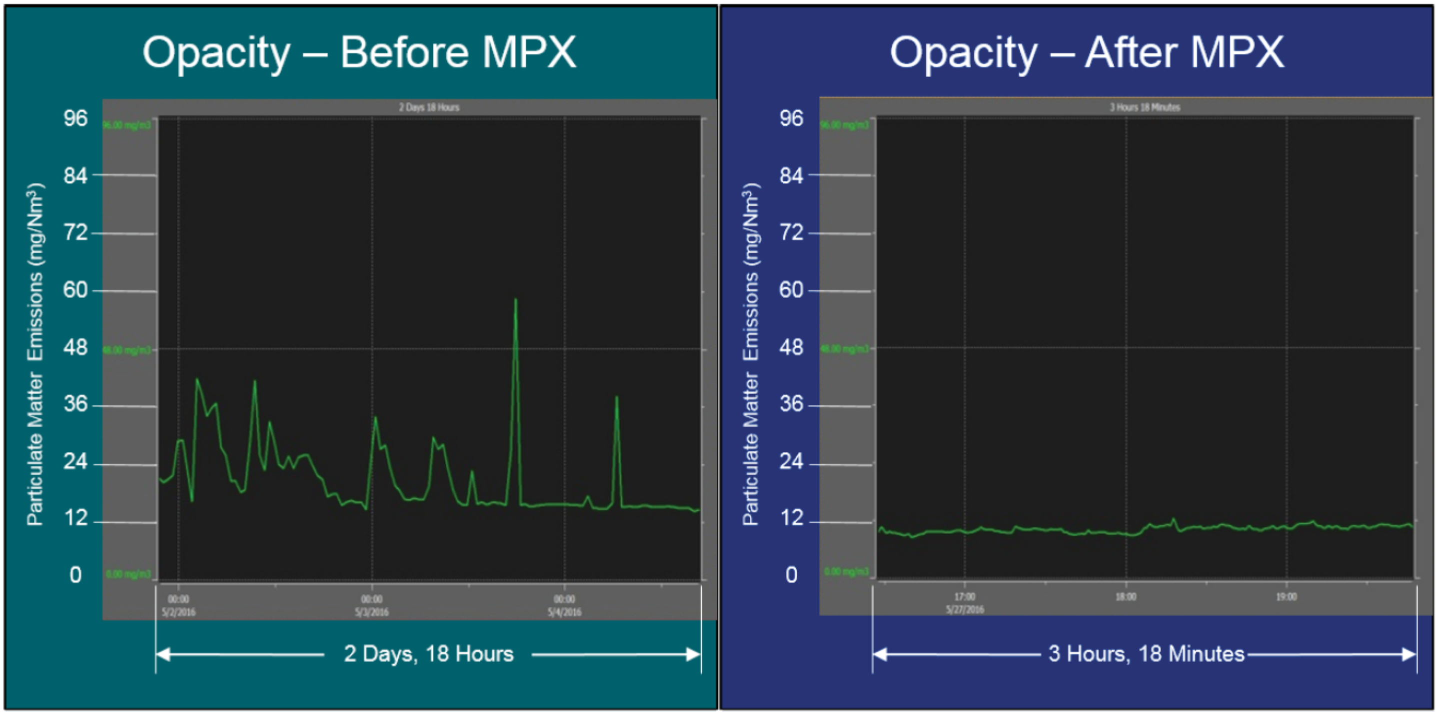
FIGURE 18: ModuPower™ MPX Ground switches mounted on ESP roof. HV cable penetration from top

commissioning site evaluation, installation supervision, commissioning, and additional support for process tuning & emission measurement verification.

After MPX commissioning, plant startup, and tuning of the MPX & rapper controls; the PM emission were confirmed to be well below target at **27.4 mg/Nm^3** using (2) MPX and (2) conventional TRSETs. No other changes or repairs were made to the precipitator during the installation. The resulting performance improvement was better than expected and allowed the plant to resume full production while maintaining emission compliance.

The MPX is able to achieve these results by supplying a more constant voltage to the ESP versus the original conventional TRSETs or 3 Phase TRSETs. This eliminated unwanted peaks in the output voltage waveform that caused excess sparking and poor performance. Therefore MPX was able to introduce more current into the ESP for better charg-

FIGURE 19: Opacity Graph, Before and After MPX



Before Condition: 4 x Conventional TRSET
Total Output Power = 49 kW

Description	Type	SV (kV)	SI (mA)	P (kW)
Field 1	TRSET	38	240	9
Field 2	TRSET	33	250	8
Field 3	TRSET	35	450	16
Field 4	TRSET	34	470	16

After Condition: 2 x MPX & 2 x Conventional TRSET
Total Output Power = 74 kW

Description	Type	SV (kV)	SI (mA)	P (kW)
Field 1	MPX	38	600	23
Field 2	MPX	34	446	15
Field 3	TRSET	34	520	18
Field 4	TRSET	36	501	18

ing which led to better collection efficiency and lower PM emission. From the tables below, the total power output to the ESP was increased from 49 kW to 74 kW or by 51%.

Following the above performance tests, additional testing was performed by taking the outlet field TRSET out of service and operating the ESP with only (2) MPX and (1) TRSET. The emission levels remained below the 30 mg/Nm^3 target. Further automation of power optimization will be performed to ensure the facility continues to operate below the emission limit while using the least amount of auxiliary power.

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BIOGRAPHY

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World-Class Technology for the Newest Waste-to-Energy Plant in the United States Palm Beach Renewable Energy Facility No. 2

Written by J.B. Kitto, Jr., M.D. Fick, and L.A. Hiner - The Babcock & Wilcox Company
W.J. Arvan - Palm Beach Resource Recovery Corporation
R.H. Schauer - Solid Waste Authority of Palm Beach County

ABSTRACT

On July 18, 2015, Palm Beach Renewable Energy Facility No. 2 (PBREF No. 2) began commercial operation following successful completion of the plant acceptance tests. The plant is owned by the Solid Waste Authority (SWA) of Palm Beach County and is the first greenfield waste-to-energy (WTE) facility to come online in North America in 20 years. Combining the best of U.S. and European WTE emissions control and metals recovery technologies, PBREF No. 2 is the cleanest, most efficient plant of its kind in the world today. Advanced technologies provide better than zero water discharge, emissions at or below the best natural gas turbines, better than net-zero greenhouse gas (carbon equivalent) footprint, and a Leadership in Energy and Environmental Design (LEED®) Platinum-level Education Center. This article begins with background on municipal solid waste (MSW) and then provides an overview of the project and plant, summary of the WTE and emissions control technologies and finally, acceptance test results and economics. PBREF No. 2 is at the forefront of renewed interest in WTE plants in North America as reliable, economical generators of renewable energy and material recycling. WTE is a key part of a comprehensive solid waste management strategy to minimize/eliminate landfilling as demonstrated in Europe and is a critical part of integrated greenhouse gas (carbon equivalent) footprint control and minimization.

INTRODUCTION and MSW BACKGROUND

Municipal solid waste (MSW) or more simply, trash or garbage, is part of everyday life. How MSW is handled, processed and disposed of involves both a need to protect the environment and an opportunity to take advantage of the resource it represents to benefit society. Waste-to-energy (WTE) plants such as Palm Beach Renewable Energy Facility No. 2 (PBREF No. 2) are part of a broader comprehensive solid waste management strategy which minimizes waste, recycles resources, recovers renewable energy and ultimately minimizes or eliminates disposal of any residuals in landfills. The goal is to manage MSW in the most productive and sustainable way possible.

The PBREF No. 2 is the first greenfield plant addition to the U.S. WTE fleet in 20 years, and is the cleanest most advanced plant of its kind in the world as of this writing. The plant design builds upon U.S. technology and experience while incorporating dramatic technology advancements over the past 20 years from Europe where hundreds of new WTE plants have been (and continue to be) placed into operation as part of Europe's aggressive program to eliminate long-term landfill needs.

According to the U.S. Environmental Protection Agency (EPA)[1-4], every person in the United States (U.S.) generated an average of 4.4 lb (2 kg) of MSW each day in 2013. In typical metropolitan areas with a population of 1.5 million people, this would result in the need to manage 3300 tons per day (TPD [3000 t_m/d]) or 1,200,000 tons (1.1 Mt_m) per year. By common convention, MSW is household and commercial waste but excludes construction and demolition debris. As shown in Figure 20, U.S. MSW contains high percentages of paper and plastics resulting in a higher heating value and lower moisture content than other MSW found around the world.

Figure 21 illustrates an integrated strategic approach to managing MSW in a way which maximizes the benefit of the material and renewable energy recovery with minimum environmental impact. Clearly, the first stage is self-evident: minimizing generation of the waste materials to start with and reusing the materials. The level of reduction here is a matter of economics (saving money), technology (product design and material recovery) and in some cases regulations which may mandate recovery. Recycling and composting are the next steps in the strategy with curbside recycling programs and home composting combined with post-collection material separation in large-scale Material Recovery and Recycling Facilities (MRRFs) and large-scale compositing facilities. The balance between individual and community programs depends upon location, cost and willingness to participate. After recycling and compost diversion, the balance of the material is largely paper and biomass/organics that contain significant quantities of usable energy. This can be used as a fuel for modern WTE plants to generate electricity and, depending upon location, steam for industrial processes and heating purposes. WTE plants also offer the capability to recover more metals and plastics depending upon the WTE technology used, thereby increasing the overall recycle rate. Finally, the inert residue from the WTE plant can be used for a variety of applications depending upon local regulations (such as aggregate for concrete, road fill and ground cover) or disposed of in a landfill.

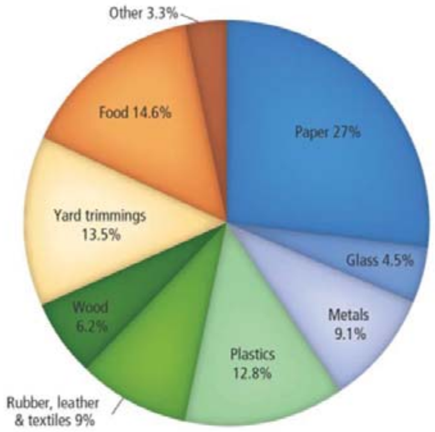


FIGURE 20: U.S. MSW generation by material, 2013 (References 2 and 4). Based upon 254.1 million tons (231 million t_m) before recycling and composting.

FIGURE 21: Integrated waste management strategy. (Reference 5)

In the U.S., the balance between recycle/compost, landfill and WTE varies widely by region and state.[5,6] In 2013, the U.S. recycled/composted 34.3% of its MSW while 52.8% was disposed of directly in landfills.[3] The balance of 12.9% was combusted in 77 WTE plants with a capacity to generate 2.5 GWe of electricity.[5] At the same time, Europe has made much greater progress in reducing MSW sent to landfills. In aggregate during 2013, the European Community (EC) recycled/composted 43% of its MSW and landfilled just 31%

with the balance of 26% processed in 459 WTE plants (90 million tons per year).[7] In some of the most advanced countries such as Denmark, 45% of the MSW is recycled/composted and 53% is processed in 27 WTE plants, leaving just 2% of the material going to landfills. (See Figure 22.)

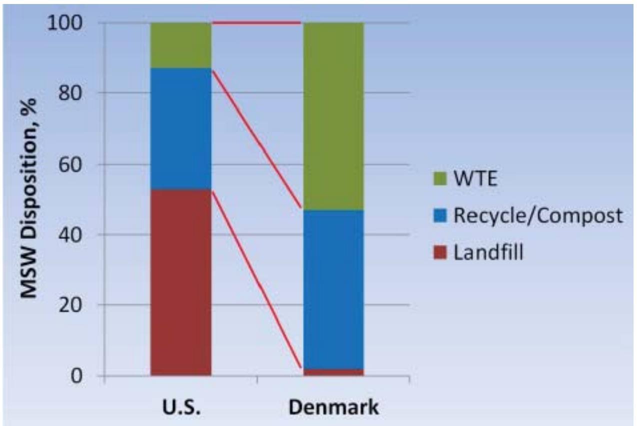


FIGURE 22: Comparison of U.S. and Denmark MSW disposition (2013).

As discussed in Reference 8, there are two basic WTE plant technologies with the decision of which to use depending upon location specific parameters and economics. The first technology is mass burn where the MSW is fed directly to the boiler system without any significant processing. The post-combustion residual is then processed to recover and recycle remaining metals while the balance is used in a beneficial application (example road-fill) or landfilled. The second technology is refuse derived fuel (RDF) where the MSW is processed first to remove metals and low-Btu residue (glass, grit, foodstuffs, etc.) before being processed into a reasonably uniform-sized fuel for combustion. With the extensive curb-side recycling programs already in place as well as limited long-term landfill capacity, PBREF No. 2 was designed using mass burn technology with state-of-the-art post-combustion metals recovery.

PROJECT OVERVIEW

In December of 2008, the Solid Waste Authority (SWA) of Palm Beach County, Florida, began the process of selecting a team to design, build and operate a new greenfield 3000 TPD (2700 t_m/d) WTE plant based upon mass burn technology with the issuance of the PBREF No. 2 comprehensive bid package and specifications. A key element in the evaluation process was a 20-year net present value analysis including capital costs, operation and maintenance costs, and beneficial revenue streams including electricity production. On April 13, 2011, SWA awarded the Design/Build contract to the Babcock & Wilcox (B&W)-led team. SWA is the owner of the facility with Arcadis serving as owner's engineer. The B&W team consisted of B&W supplying the major equipment including boilers, combustion grate systems, emissions control systems, metals recovery/processing equipment, emissions monitoring systems, and ash handling equipment, and KBR with its subcontractor CDM Smith handling the balance-of-plant material and construction. B&W also received a parallel contract for the 20-year operation and maintenance (O&M) of the new facility. PBREF No. 2 achieved commercial operation and start of the O&M contract in July of 2015 with completion of the acceptance tests.

This new plant is located adjacent to the existing SWA-owned RDF-fired WTE plant (PBREF No. 1) which B&W has operated since commercial operations began in November of 1989 (current capacity 2650 TPD [2400 t_m/d]). These facilities are the cornerstone of the SWA's Integrated Solid Waste Management System serving the 1.4 million residents of Palm Beach County and handling 100% of the MSW after the extensive curbside recycling programs.

PLANT OVERVIEW

Figure 23 (on page 19) provides an overview of PBREF No. 2 from June 2015 looking from the northeast to the southwest. PBREF No. 2 is located on a 24-acre site. The major operating segments of the plant are identified and include: the tipping floor, refuse pit (360 x 100 ft [110 x 30 m]), boilers, emissions control (spray dryer absorbers, fabric filters, carbon injection and SCR reactors), air-cooled steam condenser and turbine generator set. The ash management building houses the metals recovery systems as well as the ash processing equipment which mixes and conditions the material prior to shipment to the landfill.

The Education Center is an important element of the plant design. The SWA conducts extensive tours and educational sessions for the school children and citizens of the county describing the overall MSW management process as well as the WTE plant operation. To facilitate the educational experience, the Education Center incorporates some of the latest interactive educational displays and tools available. As shown in Figure 23 an elevated walkway connects the Education Center to the WTE complex and enables the visitors to experience all phases of the WTE operation during the walking tour. Finally, the 2-million gallon rainwater retention tank is part of the water management system discussed below.

FIGURE 23: PBREF No. 2 plant overview (from June 2015 looking from northeast to southwest).

Jog Road provides site access and serves as the eastern facility boundary. At the top right is the 23 square-mile Grassy Waters Everglades Preserve, a wildlife sanctuary which also serves as the western boundary of the facility as well as the water supply for West Palm Beach and surrounding communities. At the top left of the figure, the PBREF No. 1 serves as the southern boundary.

Figure 24 provides a sectional side-view of the plant looking west and approximately to scale. There are three independent parallel boiler/grate/emissions control lines rated at 1000 TPD (907 t_m/d) each, with one line shown in the figure. The MSW is received on the tipping floor with the majority delivered by a fleet of SWA-owned tractors with walking-floor trailers which service one of six transfer stations located across the county. MSW is also delivered by local collection trucks not serviced by a transfer station, private industry vehicles and other SWA-directed sources including PBREF No. 1 process residue and out-of-county waste. The MSW is dumped into the refuse pit where it is mixed and managed by three Konecranes semi-automated refuse cranes though no more than two cranes are required at any time. The refuse cranes also deliver the MSW to a charging hopper at the inlet to the boiler. From the hopper, the MSW is fed to the grate where the combustion process begins. The combustion is completed as the flue gas passes upward through the boiler where heat is recovered to generate steam for power generation. The cooled flue gas then passes through the emissions control equipment consisting of powder activated carbon (PAC) injection, spray dryer absorber (SDA), pulse jet fabric filter (PJFF), gas-to-gas heat exchanger, and selective catalytic reduction

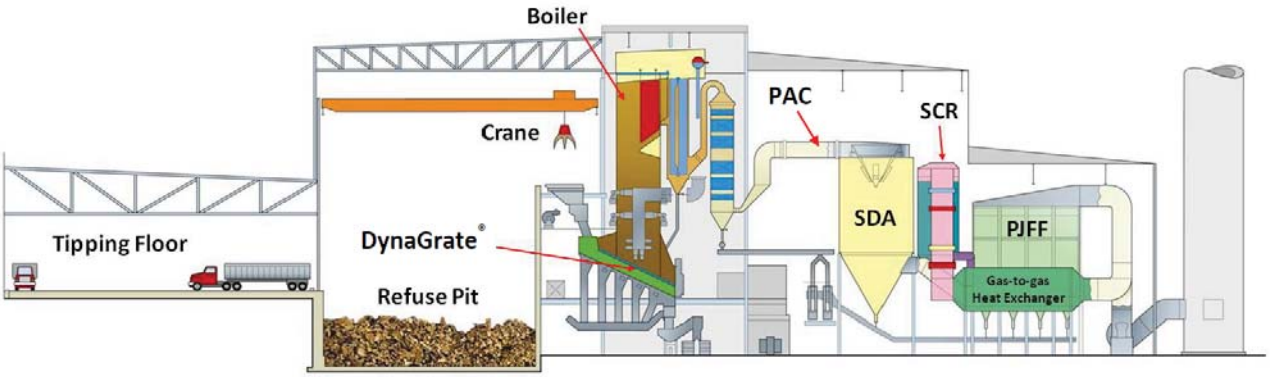


FIGURE 24: Side view of PBREF No. 2 looking west showing one of three process lines. (Not shown: turbine generator behind and metals recovery/ash management in the foreground)

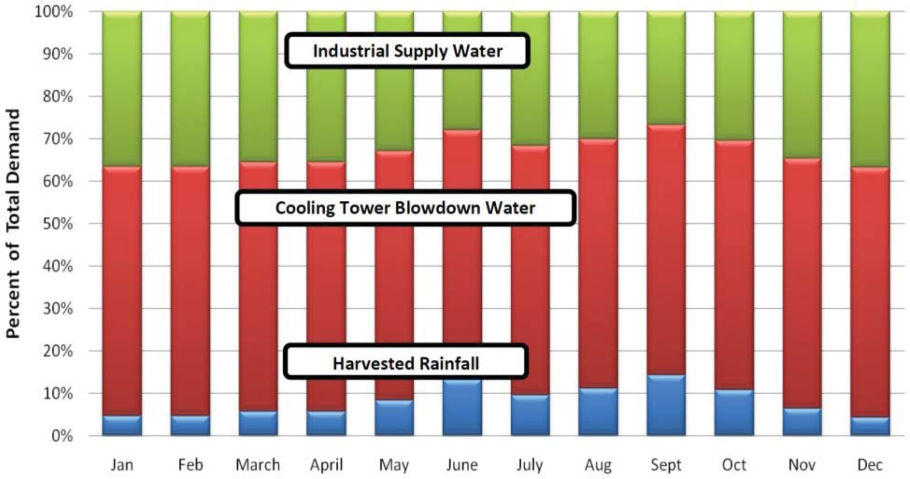
(SCR) reactor. Finally, induced draft fans exhaust the cleaned gas to the stack. Steam generated in the three boilers powers a single General Electric steam turbine generator set nominally rated at 95 megawatts (MWe), with the power, net of parasitic load, being supplied to Florida Power & Light under a power purchase agreement. Steam is exhausted from the turbine to an SPX air-cooled steam condenser and the condensate returned to the power cycle. Not shown in Figure 24 is the metals recovery system for the boiler bottom ash. Ferrous material (iron) is collected using a rotating drum electro-magnetic separator and other non-ferrous metals (predominately aluminum) are then collected using an eddy current separator.

SUSTAINABILITY AND ENERGY EFFICIENCY

Superior sustainability and energy efficiency are important to SWA. A number of major plant features focus on these areas:

1. **Water Conservation**: PBREF No. 2 has been designed around a better than net zero discharge philosophy and minimum water usage. As shown in Figure 25, the water supply for the plant includes:
    a. Harvested rainwater from the major PBREF No. 2 building roofs and the PBREF No. 1 tipping floor roof which is stored in a 2-million gallon (7.6 million liter) storage tank shown in Fig. 23. Depending upon the time of year, this source will typically supply 5 to 15% of the plant water needs.
    b. Cooling tower blowdown from PBREF No. 1 which has historically been deep well injected. This source supplies about 60% of the plant water needs — reducing the deep well injection from the total PBREF site below the PBREF No. 1 rate, thus providing better than net zero discharge for the PBREF No. 2 addition.
    c. Off-site industrial water. This source provides the balance of the water needs, seasonally ranging from 25-35% of the total plant water requirements.
    d. Neither de-chlorinated water nor potable water is required for normal plant operations.
2. **Energy Recovery**: PBREF No. 2 was designed to optimize the recovery of energy from the MSW to maximize recycle of the energy from the raw and manufactured materials back into the economic system — helping to better close the energy loop while reducing greenhouse gas emissions.
3. **Materials Recovery**: Ferrous and non-ferrous metals are recovered from the ash after the combustion process for recycle thus reducing needs for raw materials and reducing global greenhouse gas (GHG) emissions from virgin material processing.
4. **LEED Platinum Design for the Education Center**: This building was designed to U.S. Green Building Council Leadership in Energy and Environmental Design (LEED) criteria. The SWA has initiated the LEED Platinum certification process.
5. **Air-Cooled Steam Condenser**: This technology is used to replace the wet cooling towers which are normally used in WTE applications to reject heat from the power cycle, thus dramatically reducing the PBREF No. 2 water consumption.
6. **Regenerative Braking for Refuse Cranes**: When the refuse crane grapples are lowered, they use regenerative braking to generate electricity.
7. **Variable Frequency Drives**: The use of these drives for the induced draft and forced draft fans optimizes motor power consumption across the plant's range of operations, particularly when at less than full load operation.
8. **Flora and Fauna Relocation**: As part of the Design/Build contract, more than 2000 native trees, including all palm and many oak trees, were removed and replanted either on or adjacent to the site. In addition, a number of large animals, including 10 to 13 foot-long alligators were relocated from the site to the adjacent Grassy Waters Everglades Preserve.

FIGURE 25: Nominal water supply sources for PBREF No. 2.



Positive economic impacts on the local Palm Beach County communities were also a major goal of the SWA. As part of the construction and material supply sections of the Design/Build contract, extensive efforts were required to buy and hire locally (a win-win for the B&W team and the County). Approximately 20% of the total project value ($136 million) was spent with Palm Beach County businesses, with a quarter of that going to Small/Minority Business Enterprises (S/MBE). In addition, with a peak construction workforce of more than 1000 people, over 1.1 million construction labor hours were performed by Palm Beach County residents, exceeding the B&W team's 45% commitment.

SUSTAINABILITY — LANDFILL IMPACT

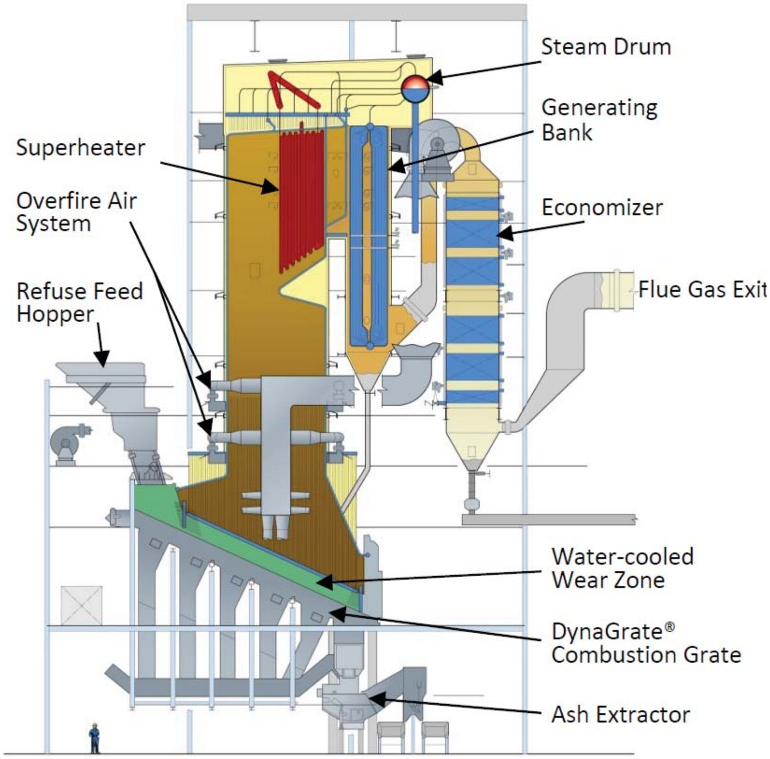
The mass burn WTE process reduces the volume of material which will need landfilled by up to 90% while also effectively eliminating the residual organic compounds (combusted in the WTE process) — even potentially eliminating landfill for that portion of the residual which can be used for other beneficial applications such as road fill, concrete aggregate or ground cover. As a critical part of the project, the volume reduction significantly extends the life of the existing SWA landfill by many years. This eliminates the short-term and mid-term need for the siting, permitting, acquisition, start-up costs and operating costs of a new landfill while eliminating the environmental impact and risks of the expanded landfill footprint. As discussed later under Greenhouse Gases, methane gas emissions from the new landfilled MSW are eliminated and energy recovered. Odors from new landfilled MSW materials are eliminated with the destruction of the source organic compounds. Finally, the WTE process effectively eliminates new MSW landfill gaseous emissions of a variety of hazardous volatile organic and chlorinated hydrocarbons including ammonia, mercaptains/sulfides, toluenes, dichloromethane, and acetone among others.

BOILER, GRATE AND COMBUSTION TECHNOLOGIES

Three independent parallel 1000 TPD (907 t_{m}/d) mass burn lines process the MSW in three B&W Stirling® power single-pass mass burn boilers shown in Figure 26. While several boiler design options are available from B&W for mass burn applications as discussed in Reference 8, the single-pass design offered the best value proposition for PBREF No. 2. Referring to Figure 26, MSW from the refuse storage pits is transferred to the refuse feed hopper by the refuse cranes and is then fed into the boiler/grate system by hydraulic ram actuators. The refuse combustion is begun on the B&W Volund DynaGrate® pivoting combustion grate. The combustion products or flue gases then pass vertically up through the furnace where the combustion is completed by the addition of more air through the B&W Precision Jet® overfire-air system. The furnace design in modern WTE systems is critical. Proper design permits at least two (2) seconds of residence time above 1800F (982C) to destroy dioxins (polychlorinated dibenzo-para-dioxins [PCDD]) and furans (polychlorinated dibenzofurans [PCDF]) which can be formed during the combustion of plastics in the MSW. The overfire-air system also minimizes the formation of nitrogen oxides (NO_x) and carbon monoxide (CO). Further emissions reductions are achieved in the post-combustion emissions control equipment.

The flue gas is then cooled to recover heat as it passes through the remaining boiler furnace and heat transfer surfaces before flowing to the emissions control equipment. Each boiler provides 284,400 lb/hr (35.8 kg/s) of steam at 900 psi (6.2 MPa) and 830F (443C) to the turbine for power generation at maximum continuous rating (MCR). The boilers incorporate the best in modern U.S. and European design practice including: total Inconel® weld overlayed furnaces to provide protection from the corrosive flue gases, minimal use of re-

FIGURE 26: B&W Stirling® mass burn power boiler schematic.



fractory to reduce maintenance expense, water-cooled wear zone to minimize slagging, erosion and corrosion near the grate, and superheater heat transfer surfaces with access for easy replacement. A key advantage of B&W's combustion technology, unlike other designs, is that flue gas recirculation (combustion products recirculated to the combustion zone) is not required to minimize NOx formation. Such flue gas recirculation systems result in added capital and O&M costs and reduced boiler availability.

The B&W Volund DynaGrate combustion grate shown in Figure 27 is modular in design with two modules wide and four modules in the direction of fuel flow in each boiler. The grate consists of an alternating series of horizontal and vertical bars across each module which rotate slowly back and forth 60-degrees to create a mixing-tumbling motion. This action continuously mixes the fuel exposing fresh surface for combustion and moves the refuse continuously down the inclined grate surface from the ram charger inlet to the ash discharge. Primary combustion air is admitted from below through well-defined air gaps between the rotating grate bars. This patented rotating bar design provides very uniform air flow across the grate surface and avoids pluggage of air holes used with other grate systems. The grate speed of each module is independently controlled as is the air flow to each module permitting the integrated control system to optimize the combustion over each of the eight grate module surfaces. The overall result is a combustion system that consistently yields very low unburned carbon in the ash and very low CO concentrations in the flue gas (maximizing combustion efficiency while minimizing emissions). Lack of contact between the bars and between the bars and sidewalls minimizes wear and associated maintenance. All mechanical linkages and equipment rotating the bars are external to the grate module and boiler providing superior maintenance access.

FIGURE 27: B&W Volund DynaGrate® pivoting combustion grate.

Extensive computer modeling was used (Figure 28 on page 23) to design the overfire air system and to ensure maximum combustion efficiency and minimum formation of CO, NOx and other pollutants. As shown in Figure 28, two levels of secondary air injection nozzles are provided in the PrecisionJet system. The large low-pressure nozzles are staggered and interlaced between the front and rear walls of the boiler furnace to maximize coverage and mixing. As shown, an additional set of air nozzles is provided above the inlet to the grate for enhanced fuel drying control.

AUTOMATED REFUSE CRANE TECHNOLOGY

Three Konecranes refuse cranes (see Figure 29 on page 23) with grapples are part of PBREF No. 2 fuel feed system with no more than two cranes required for routine operations at any one time. A spare crane is provided to allow for out-of-service maintenance work. The cranes provide fuel management and mixing in the refuse pit as well as transfer refuse from the pit to the boiler charging hoppers. Each crane is capable of lifting 16 t (14.5 t_m) each. Fuel management with the cranes can be executed using manual, semi-automatic or fully automatic operation. The cranes can be operated in a fully automated mode without a dedicated operator, such as at night when there are no MSW deliveries. The cranes can travel at 300 ft/min (1.5 m/s) and include anti-sway and anti-collision automation. The cranes also use regenerative braking to recover energy as the grapples are lowered to the refuse pit, reducing electricity usage.

POST-COMBUSTION EMISSIONS CONTROL TECHNOLOGY

The PBREF No. 2 post-combustion emissions control system, in combination with the combustion system, provides for the control of primary and secondary pollutants below permit levels. Post-combustion NOx control is achieved by selective catalytic reduction (SCR). Acid gases (predominantly sulfur dioxide [SO_2] and hydrogen chloride [HCl]) are removed using the spray dryer absorber (SDA) in combination with the pulse jet fabric filter (PJFF). Particulate including metals and lead are controlled by the PJFF. CO, volatile organic carbons (VOCs) and

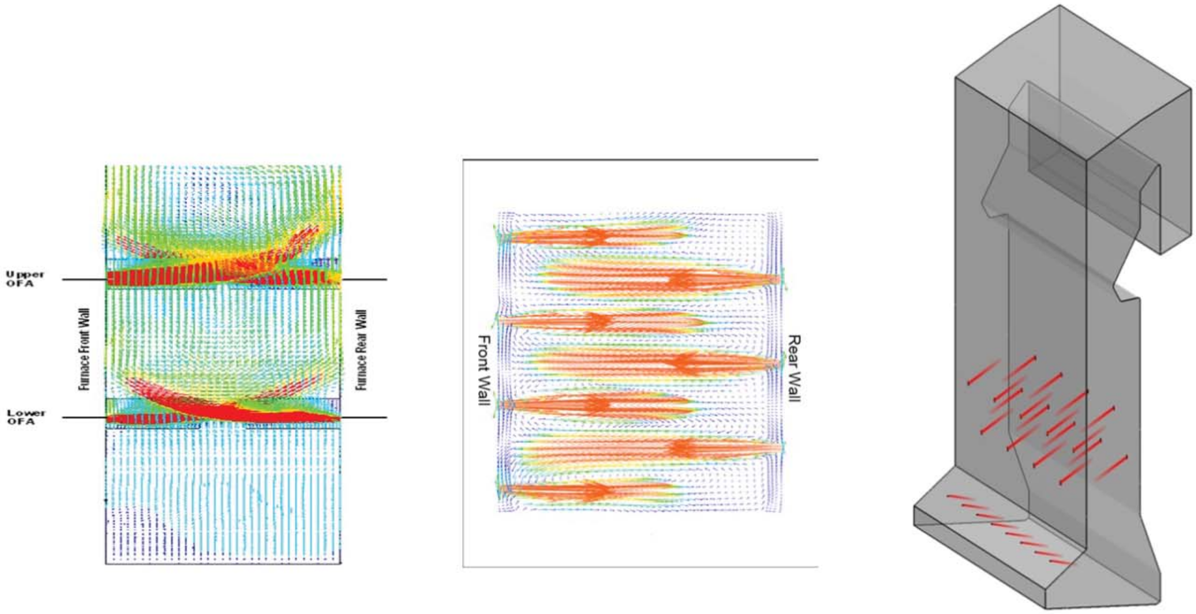
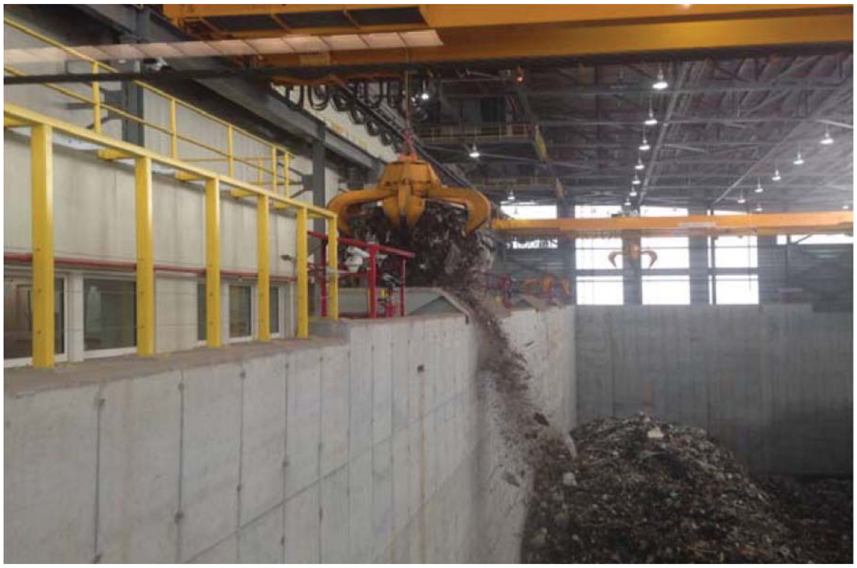


FIGURE 28: Combustion modeling for PrecisionJet® air system.

dioxins/furans are primarily controlled through the combustion process, but powdered activated carbon (PAC) injection in combination with the PJFF provides additional dioxin/furan control. Finally, mercury (Hg) is controlled by the PAC injection in combination with the fabric filter.

The post-combustion emissions control system for the three MSW lines is shown in Figure 30 on page 24. Flue gas from the boilers enters on the left. PAC is injected into the flue gas before entering the vertical SDA for acid gas control and mixing of the flue gas with the PAC. The flue gas exits the SDA at the desired relative humidity, which for PBREF No. 2 typically corresponds to an SDA outlet temperature range of 280 to 290F (138 to 143C) and passes through the PJFF for particulate removal, including fly ash, unreacted lime reagent from the SDA, and reaction products from the SDA and PAC injection. Flue gas leaving the fabric filter then passes through a reheat heat transfer system to increase the flue gas temperature to ~450F (232C) before passing vertically downward through the SCR reactor to further reduce NOx emissions. Following the SCR, the flue gas passes back through the heat exchanger system to recover energy back into the power cycle before passing through the induced draft fans and ultimately the stack. The system shown is designed for a minimum footprint for reduced capital costs and for maximum energy recovery to keep plant efficiency high.

FIGURE 29: Automated refuse crane technology.



While all of the post-combustion technologies are discussed in detail in References 8 and 9, the following material touches on some of the key elements with reference to PBREF No. 2. The PAC system provides for fine powdered carbon injection into the flue gas upstream of the SDA for control of mercury and residual dioxins and furans. The PAC is stored outside of the building in vertical silos and is pneumatically conveyed to the injection point. The SDA provides mixing to maximize contact with the flue gas. The spent and unreacted PAC is then collected in the PJFF.

Lime slurry is injected into the SDA for acid gas removal (SO_2, HCl, HF and H_2SO_4). The lime slurry is injected downward through a mechanical atomizer and mixed with the flue gas introduced into the SDA though a gas disperser as-

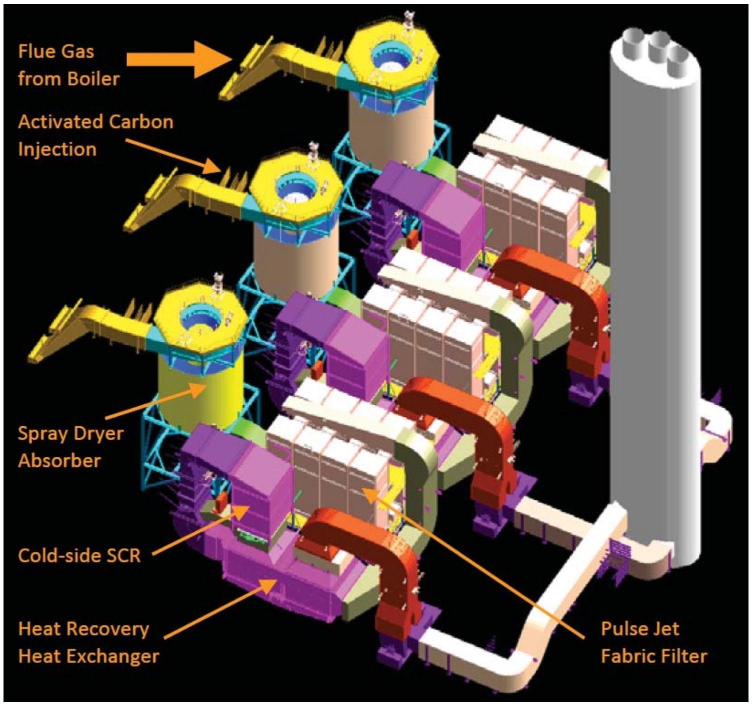


FIGURE 30: Post-combustion emissions control technology.

sembly. Pebble lime is stored outside of the building in a vertical silo and then mixed/slaked with water to create the lime slurry for injection. For rapid load response, additional water is injected separately into the SDA to provide control of the flue gas humidity (a key performance parameter for acid gas removal and lime utilization) which is monitored at the SDA exit. The reaction products and the unreacted lime are collected in the PJFF. Additional acid gas absorption takes place as the flue gas passes through the particulate filter cake and unreacted lime on the upstream side of the filter bags.

The PJFF collects particulate on the outside of vertically hung tubular filter bags within the fabric filter enclosure as the flue gas passes vertically upward outside and then through the PTFE (polytetrafluoroethylene) membrane-coated bag material. A filter cake consisting of ash, reaction products, unreacted lime and PAC collect on the outside of the bags. The filter cake is periodically removed from the bag by periodic bursts of high pressure air directed down the bags and collected in the bottom hoppers for transfer to the ash management building. The filter cake also removes additional pollutants as the flue gas passes through the unreacted reagents.

The SCR NOx reduction system is the first such system installed on a WTE application in North America. This is a low dust (after PJFF) and low temperature system. Vaporized aqueous ammonia is injected through a manifold and injection grid system into the flue gas upstream of the catalyst reactor. The flue gas then passes vertically downward through the Ceram ceramic catalyst blocks where NOx is converted to nitrogen (N_2) and water vapor (H_2O) through reaction with the ammonia (NH_3) in the presence of the catalyst. The catalyst consists primarily of titanium oxide with small amounts of other material to enhance low temperature performance and resist degradation. The 19% aqueous ammonia solution is stored outside of the building in a contained storage tank. The reactor is designed to accept a number of different catalysts when the catalyst is ultimately removed because of deactivation. The reactor is also positioned within the emissions control building to permit rapid catalyst replacement. The SCR system also has the added benefit of further reducing the emissions of any remaining dioxins and furans in the presence of the catalyst.

Finally, the SCR flue gas reheat/heat recovery system provides the critical flue gas temperature necessary for optimal catalyst operation without firing natural gas or penalizing the power plant efficiency as shown in Figure 31 (on page 25). After the flue gas leaves the PJFF it passes first though a gas-to-gas heat exchanger which heats the flue gas close to the required temperature by using the waste heat in the flue gas leaving the SCR reactor. The flue gas then passes through a steam coil gas heater which uses steam extracted from the boiler drum to achieve the target ~450F (~232C) flue gas temperature. After the SCR reactor, the flue gas then passes back through the gas-to-gas heat exchanger to recover part of the energy in the flue gas. It then passes through a finishing heat exchanger which utilizes low temperature boiler feedwater to extract the last of the energy and reduce the gas temperature to the desired stack temperature (~295F [146C]). Thus the reheat/heat recovery system is fully integrated into the power cycle to maximize plant thermal efficiency.

POWER, METALS RECOVERY AND EMISSIONS ACCEPTANCE TEST RESULTS

MSW throughput, thermal performance, metals recovery, noise, plant reliability and emissions tests were conducted in the summer of 2015 as part of the formal PBREF No. 2 acceptance. Acceptance tests were conducted over a 30-day period where continuous operation was required and a number of individual heat rate (thermal efficiency) and emissions tests were conducted. PBREF No. 2 exceeded all MSW throughput requirements.

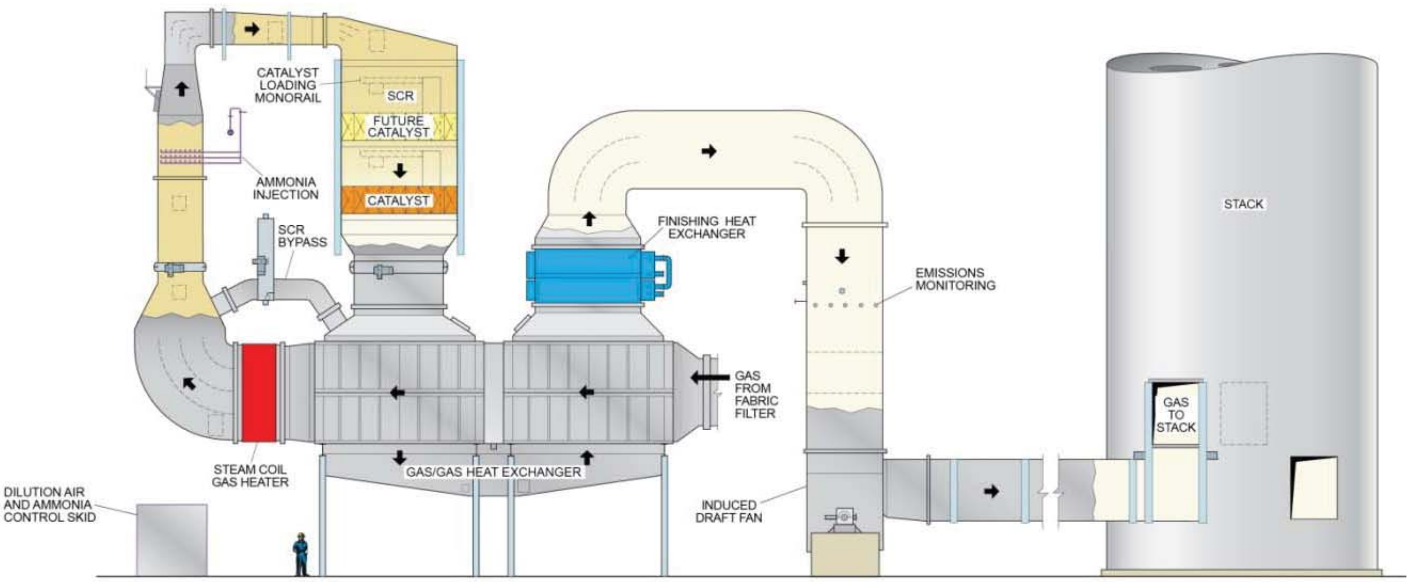


FIGURE 31: SCR reheat and heat recovery system.

During the continuous operation test period, three 8-hour thermal efficiency performance tests were conducted in accordance with ASME PTC-34 Performance Test Code.[10] The B&W team guaranteed an electrical generation rate of 625 kWh per ton of reference MSW with 5000 Btu/lb heat content. This is equivalent to a more conventional power plant heat rate of 16,000 Btu/kWh which is at the lower end (higher efficiency) of state-of-the-art WTE facilities. During the performance tests, the three measured heat rates (as corrected by PTC-34) ranged from 666 to 677 kWh/reference ton or 6 to 8% higher than the guarantee value making PBREF No. 2 one of the best in class for modern mass burn units of its kind.

Tests were also conducted to verify the guarantees for ferrous and non-ferrous metal recovery from the bottom ash of the three units. The ferrous recovery rate guarantee was 90%. Over the test period, the ferrous recovery system recovered 97.2% of ferrous metals. The non-ferrous recovery rate guarantee was 85%. Over the test period, the non-ferrous recovery system recovered 88.6% of the non-ferrous metals.

Three 4-hour emissions tests were also conducted on each of the three units by an independent contractor over the continuous operation acceptance test period providing nine total sets of emissions results. The results for the primary pollutants are summarized in Figure 32. This table also provides the PBREF No. 2 permit emissions limits as well as

FIGURE 32: PBREF No. 2 Emissions – As Good as or Better Than a Gas Turbine

Pollutant	Natural Gas Turbine Exhaust [Note 1]	PBREF No. 2 Emissions Permit	PBREF No. 2 Actual Emissions Test [Notes 2, 3]
Nitric Oxide	20 – 220 ppm	< 50 ppm	30 – 31 ppm
Nitrogen Dioxide	2 – 20 ppm	Included above	Included above
Carbon Monoxide	5 – 330 ppm	< 100 ppm	15 – 24 ppm
Sulfur Dioxide	Trace – 100 ppm	< 24 ppm	10 – 21 ppm
Sulfur Trioxide	Trace – 4 ppm	Not required	Not detectable/Trace
Unburned Hydrocarbons	5 – 300 ppm	< 7 ppm	0.2 – 2.7 ppm
Particulate Matter	Trace – 25 ppm	12 mg/dscm	0.6 – 2.5 mg/dscm

- All data shown for typical concentration (parts per million volume) except where noted

Note 1: Natural gas data source: *Gas Turbine Emissions and Control*, GE Power Systems white paper

Note 2: PBREF No. 2, data source: Babcock & Wilcox

Note 3: Actual emissions test conducted during compliance test, three 4 hr. test per unit – 9 total tests with range showing high and low measurement under stable full load testing the emissions from natural gas turbines for comparison purposes. Key results include:

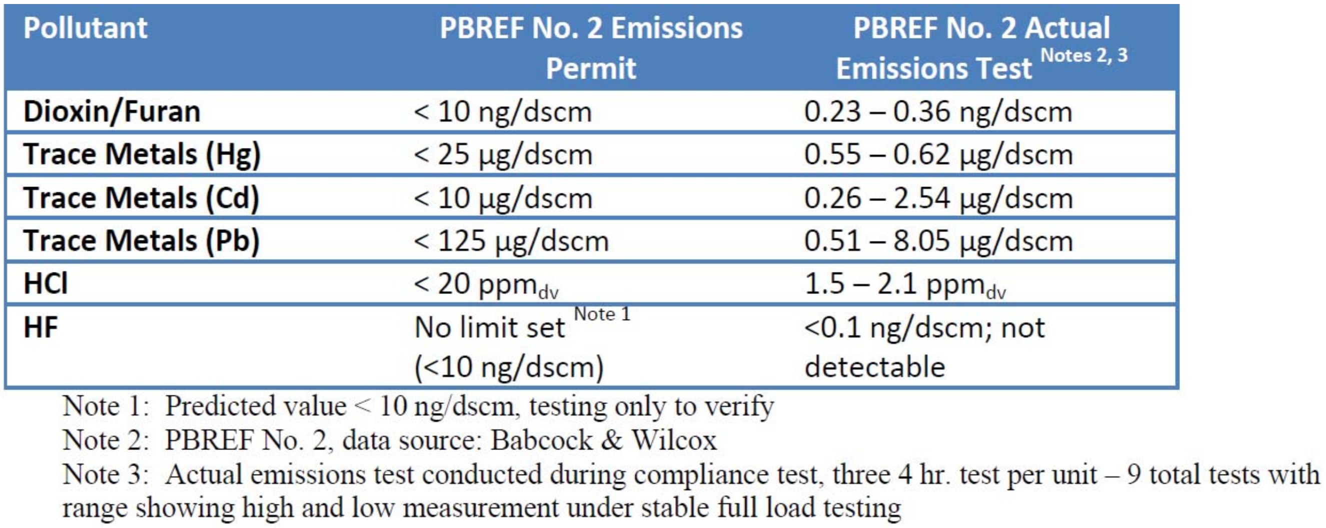
1. PBREF No. 2 achieved all of its permit emissions guarantees in every case with values significantly below the permitted levels.
2. The PBREF No. 2 emissions results are at the low end of or below the emissions of natural gas-fired turbines.

Figure 33 provides the results for emissions that are of particular concern for WTE facilities. The PBREF No. 2 permit emissions limits are provided for comparison.

1. PBREF No. 2 achieved results below all of its permit emission limits.
2. Many of the PBREF No. 2 results are an order of magnitude below the emissions limits making it the best in class of WTE facility in the U. S. and the world.

To put these results into perspective and to understand the major advancements of today's modern WTE facilities as compared to the original emissions results of WTE plants constructed thirty years ago, it is worthwhile to consider the emissions of dioxins/furans. During the 1980s before the importance of WTE facility dioxin/furan emissions were fully understood, WTE facilities had dioxin/furan emissions equivalent to over 10,000 ng/DSCM. The cause was primarily due to small hot combustion furnaces (for low initial capital cost) without the volume or flue gas residence time at elevated temperatures (1800F [982C] or higher) to control pollutant formation and destruction, as well as the lack of post-combustion controls. In contrast, PBREF No. 2 dioxin/furan emission results of 0.36 ng/dscm are more than four orders of magnitude below the results in the 1980s for a reduction of more than 99.996%. The EPA has indicated that WTE

FIGURE 33: Emissions of WTE-Sensitive Pollutants – Best of Class for WTE Systems



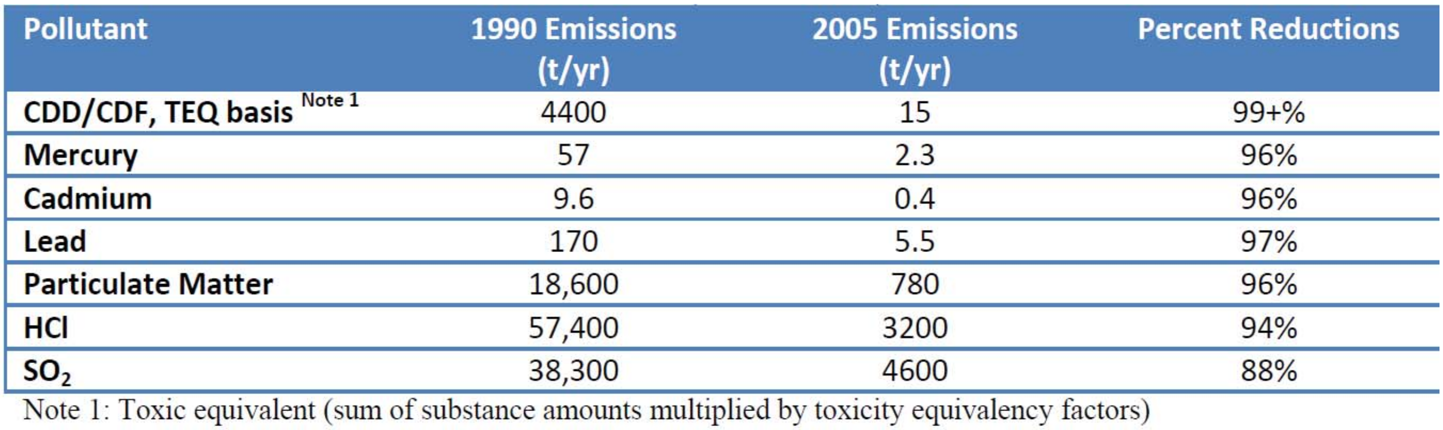
Pollutant	PBREF No. 2 Emissions Permit	PBREF No. 2 Actual Emissions Test [Notes 2, 3]
Dioxin/Furan	< 10 ng/dscm	0.23 – 0.36 ng/dscm
Trace Metals (Hg)	< 25 µg/dscm	0.55 – 0.62 µg/dscm
Trace Metals (Cd)	< 10 µg/dscm	0.26 – 2.54 µg/dscm
Trace Metals (Pb)	< 125 µg/dscm	0.51 – 8.05 µg/dscm
HCl	< 20 ppm_{dv}	1.5 – 2.1 ppm_{dv}
HF	No limit set [Note 1] (<10 ng/dscm)	<0.1 ng/dscm; not detectable

Note 1: Predicted value < 10 ng/dscm, testing only to verify

Note 2: PBREF No. 2, data source: Babcock & Wilcox

Note 3: Actual emissions test conducted during compliance test, three 4 hr. test per unit – 9 total tests with range showing high and low measurement under stable full load testing

FIGURE 34: Emissions Reductions from Large and Small WTE Units from 1990 to 2005 As Reported by the U.S. EPA (Reference 11)



Pollutant	1990 Emissions (t/yr)	2005 Emissions (t/yr)	Percent Reductions
CDD/CDF, TEQ basis [Note 1]	4400	15	99+%
Mercury	57	2.3	96%
Cadmium	9.6	0.4	96%
Lead	170	5.5	97%
Particulate Matter	18,600	780	96%
HCl	57,400	3200	94%
SO_2	38,300	4600	88%

Note 1: Toxic equivalent (sum of substance amounts multiplied by toxicity equivalency factors)

industry retrofits and compliance measures to meet current emissions regulations have reduced annual emissions from all U.S. WTE plants in aggregate from an estimated 18 lb (8.2 kg) of dioxin toxic equivalents in 1987 to an aggregate total of less than 0.5 oz (14 g) per year today.[11,12] PBREF No. 2 measured emissions (Figure 33) are more than an order of magnitude less than today's stringent emissions limits. The EPA has also recognized dramatic emissions reductions in other WTE plants as indicated in Figure 34.

Finally, even when MSW is buried directly in a state-of-the-art sanitary landfill, landfill gas (in addition to methane and CO_2 discussed below) contains a variety of VOCs and chlorinated hydrocarbons.[13] These include ammonia, mercaptains/sulfides, toluenes, dichloromethane, and acetone among others, in significant concentrations which adversely impact the environment. 3000 TPD (2700 t_m/d) MSW disposed of in a landfill, instead of employing WTE, would produce 58 to 93 t/yr (53 to 84 t_m/yr) of these compounds based upon the rates discussed by Reference 13.

GREENHOUSE GAS (GHG) EMISSION AVOIDANCE THOUGH WTE

WTE facilities significantly reduce the global greenhouse gas emissions footprint. In general terms, this includes three major elements:

1. **Renewable Component Impact on Net CO_2 Emissions**: Approximately two-thirds of MSW falls under categories considered by the U.S. EPA as renewable fuel assuming that rubber, leather and textiles categories are approximately evenly split between natural and manmade products (see References 3 and 4). The bulk of the renewables is paper/board products, wood, food waste and yard trimmings. Recent EPA analyses of municipal solid waste combustion indicate that WTE facilities produce lower net GHG emissions than fossil fuel sources as shown in Figure 35.[12] This figure clearly shows the impact of the renewable component in MSW on the net GHG emissions (1016 pounds of CO_2/MWh) compared to coal, oil and natural gas fossil fuels. Calculations from the PBREF No. 2 performance tests are consistent with this. The MSW renewable portion at PBREF No. 2 is relatively high because of the higher proportion of yard and other biomass waste present.

2. **Recovered/Recycled Metals**: Post-combustion recovery of metals from PBREF No. 2 also reduces the GHG footprint by avoiding the net energy difference between recycling metals and producing metals from virgin ore. For ferrous metals recovered, 56% of the energy for virgin ore production is avoided.[14] The typical 2000 t/month (1814 t_m/month) of ferrous metal recovered from PBREF No. 2 avoids the use of 16,800 t (15,241 t_m) of coal and 14,400 t (13,063 t_m) of limestone on an annual basis. For the non-ferrous metals recovered (assuming aluminum), 90% of the energy to produce aluminum ingots from virgin ore production is avoided.[14] The typical 100 t/month (90.7 t_m/month) of non-ferrous metal recovered from PBREF No. 2 avoids the equivalent use of 1.5 million gallons (5.7 million liters) of gasoline per year. Combining ferrous and non-ferrous results, post-combustion metals recovery at PBREF No. 2 further reduces the GHG footprint by 170 pounds of CO_2/MWh.

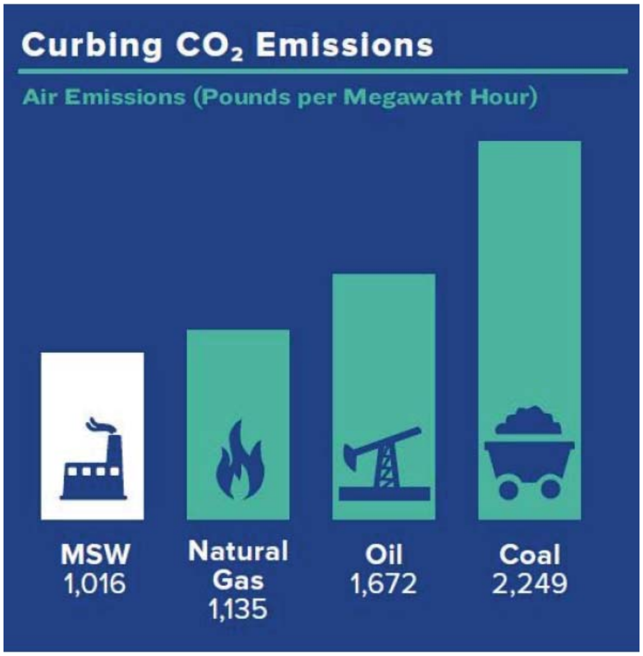


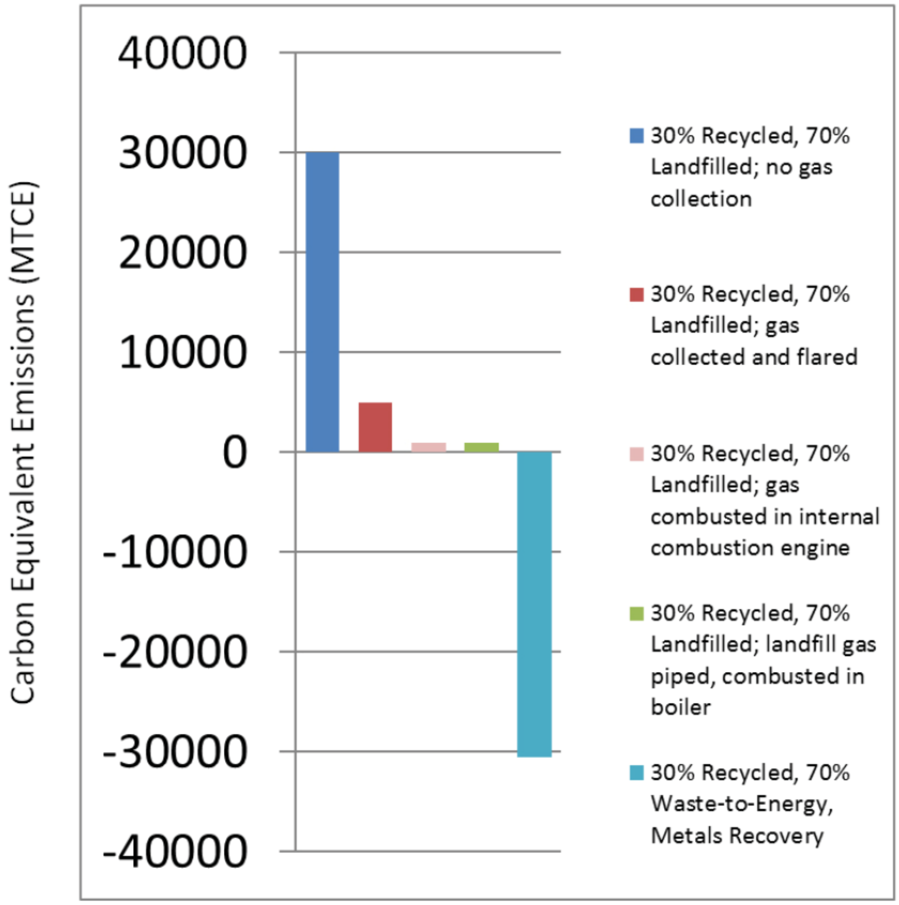
FIGURE 35: Waste-to-energy produces lower CO_2 emissions than fossil fuel sources. (Reference 12)

3. **Methane (CH_4) Offset**: When MSW is landfilled, anaerobic biodegradation of the organic components in MSW generates CO_2 and CH_4 in approximately equal proportions[15,16], with methane produced at a rate between 0.03 and 0.04 ton CH_4 per ton of MSW on a dry basis.[15] This is equivalent to 0.02 and 0.03 on a wet basis using typical as-delivered moisture content of 31%.[8] These landfill emission rates result in 61 to 83 t (55 to 75 t_m) of landfill methane emissions per day being avoided by using a 3000 TPD (2700 t_m/d) WTE facility such as PBREF No. 2. Methane in the atmosphere is relatively short-lived compared to CO_2,

and therefore the exact global warming potential (GWP, conversion to CO_2 equivalent on a mass basis) declines over time with the value highly variable depending upon the analysis assumptions and the life-cycle time. The U.S. EPA indicates that for 100 years, the GWP for methane is 28 to 36 and for 20 years, it is 84 to 87.[17] To provide some level of consistency from year-to-year and to reflect the relatively short-term nature of GHG emissions targets being considered, many GHG analyses (example in Reference 18) use the 20-year United Nations Intergovernmental Panel on Climate Change Assessment Report No. 4 global warming potential of 72 for methane.[19] Using this global warming potential, the 61 to 83 t/d (55 to 75 tm/d) of methane avoided is equivalent to avoiding 4000 to 6000 pounds of CO_2 emissions per MWh of WTE generated power.

From this simplified analysis, the renewable fuel portion of MSW, the emissions impact of the post-combustion metals recycle, and the avoidance of landfill methane emissions provides a significant net reduction in GHG emissions with WTE technology, and thus, a negative GHG footprint.

FIGURE 36: Net impact of WTE plant on greenhouse gases. (Reference 20)



More comprehensive integrated life-cycle analyses of GHG emissions from MSW have been conducted under a broad range of scenarios using the U.S. EPA's municipal solid waste decision support tool (MSW-DST) by Thorneloe et al.[20] This analysis was based upon a 481,700 t/yr (437,000 t_m/yr) MSW stream or 1320 TPD (1200 t_m/d) with an average U.S. MSW composition. A 75% gas collection efficiency is assumed for cases based upon landfill gas collection. The annual GHG results for five important cases are shown in Figure 36. The general conclusion is that WTE with recycling provides a net GHG reduction compared to the net positive GHG emissions for just landfill with recycle. Again referencing the U.S. EPA, approximately one ton of net GHG emissions are reduced for each ton of MSW combusted in a WTE plant.[12]

ECONOMICS

Clearly, capital cost and levelized cost per ton of WTE play important roles in wider acceptance and utilization in the U.S. Economic benefits of WTE plants include:

- Revenue from energy recovery
  - Electricity sales
  - Steam sales (combined heat and power applications)
  - Localized energy recovery credits as a renewable portfolio contributor
- Revenue from metal recovery
- Reduced landfill costs
  - Mass burn technology reduces volume to the landfill by up to 90%
  - Further cost reduction when the remaining ash is utilized as concrete aggregate, road fill or cover material
- Reduced costs for future landfill
  - Reduced need by extending the current landfill life
  - Elimination of future landfill permitting costs
- Community employment
  - Temporary construction jobs and job training
  - Permanent plant opera-

    tions, maintenance and administrative careers
- Local community services impact
    - Hotels, restaurants, etc.
    - Local goods and services suppliers

The SWA has reported that the total amended cost of the PBREF No. 2 was $674,000,000.[21] Based upon the 3000 TPD (2700 t_m/d) facility capacity, the unit price is $224,700 per TPD capacity. This value is less than the inflation-adjusted WTE plants built 20 years ago, demonstrating the impact of current state-of-the-art technology and major efforts to modularize many plant components to reduce construction cost and time. However, more important than capital cost in the long run is the tipping fee (amount paid to dispose of a ton of MSW) and how it compares to landfilling alone. Clearly, landfill costs vary widely by region. For Palm Beach County Florida, current SWA analysis concludes that the PBREF No. 2 WTE plant has about the same cost as the direct landfilling at approximately $25/ton. This analysis excludes the problems and costs of landfilling in the future and should only improve as depressed commodity prices stabilize and renewable energy credits become available.

CONCLUSION

After groundbreaking in April of 2012, the Palm Beach Renewable Energy Facility No. 2 has transitioned to commercial operation following successful completion of formal acceptance testing in July of 2015. (See Figure 37.) The facility incorporates the latest advanced technologies from the U.S. and Europe to provide the cleanest and most advanced efficient WTE facility of its kind in the world today — generating renewable energy and reducing net greenhouse emissions.

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FIGURE 37: PBREF No. 2 at twilight.

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Reducing the Cost of Mercury Control with Fuel Additives

Written by Connie Senior and Sharon Sjostrom, ADA-ES, Inc.

SUMMARY

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 absorption of oxidized gaseous mercury species (collectively, Hg^{2+}) in aqueous media. Any mercury control strategy must utilize one or both of these pathways, either by removing particulate-bound Hg using the particulate collection device or by removing gaseous Hg^{2+} in a flue gas desulfurization (FGD) scrubber.

Oxidation of the elemental mercury (Hg^0) that is present in the flame zone is the key step in the transformation of mercury into forms that can adsorb and/or absorb in downstream air pollution control equipment. Halogen compounds have long been identified as the most important species for oxidizing mercury in coal combustion systems. Chlorine is the most abundant halogen in coal, but is less effective at mercury oxidation than bromine. Iodine has been shown to be the most effective halogen on an equivalent molar basis for the homogeneous oxidation of mercury in combustion flue gas.[1]

HALOGEN ADDITION TO COAL-FIRED BOILERS

There is not enough native iodine or bromine in most U.S. coals to affect mercury oxidation in coal-fired boilers: the bromine content of U.S. coals is 1% to 4% of the chlorine content,[2] and iodine concentrations are typically lower than bromine concentrations. Therefore, if additional mercury oxidation is desired, iodine or bromine has been added to the coal before combustion or to the flue gas. A photo of a typical coal additive skid is shown in Figure 38.

Configurations in which adding halogens to the fuel or flue gas is advantageous for mercury emissions control include the following:

- A low-halogen fuel and the use of a non-brominated PAC (in the case where this combination is cheaper than brominated PAC by itself);
- A low-halogen fuel on a unit with a wet or dry FGD with the intent of using the scrubber as the primary mercury removal device;
- Refined coal use, which is a modification of the fuel to result in sufficient demonstrated emission reductions, typically of NOx and mercury to qualify for tax credits under a U.S. tax regulation (IRS Section 45). This tax credit only applies to the qualified fuel purchase and does not supersede compliance with the MATS rule.

The addition of iron or other transition metals can also act as catalysts to improve the effectiveness of halogens for mercury oxidation.[3]

ABSORPTION OF MERCURY ON CARBON

In a coal-fired power plant, the fly ash often contains unburned carbon from less-than-complete combustion of the coal. This unburned carbon can adsorb mercury. Activated carbon sorbents are more effective than unburned carbon in fly ash because of higher specific surface area and, in some cases, an optimized pore structure or surface treat-

FIGURE 38:
Photo of Simple Coal Additive Skid

ments specific to mercury capture. However, without sufficient halogen, neither unburned carbon nor activated carbon is very effective at adsorbing mercury.

Coal halogen injection has been used successfully to control mercury in conjunction with non-halogen treated powdered activated carbon (PAC) injection. Data from a boiler firing subbituminous coal with an ESP and using a non-brominated PAC with and without halogen addition are summarized in Figure 39 for iodine addition. Injection temperatures ranged from 315-330°F across all tested conditions. Non-brominated PAC was used alone or in conjunction with low-level iodine injection (3 to 7 µg/g I on coal). It should be noted that these are comparisons of actual plant data and performance will vary from plant to plant.

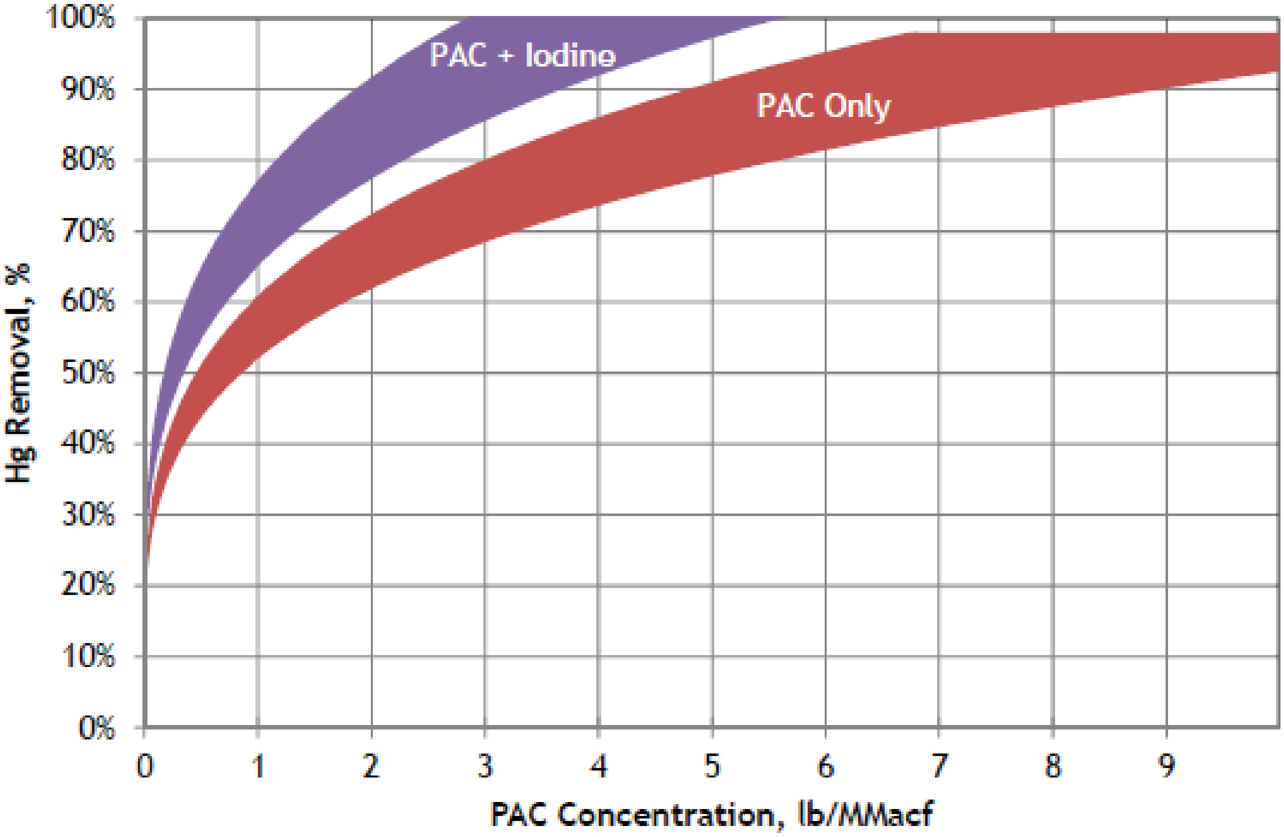
Direct comparisons of the relative effectiveness of bromine and iodine for mercury control have not been widely reported. Figure 40 (on page 33) illustrates the impact of halogen addition on the fraction of oxidized mercury at the ESP outlet of a subbituminous-fired boiler.[4] For similar levels of oxidation about ten times as much bromine as iodine is required (on a mass basis), and this is expected to apply to the use of halogen plus non-brominated PAC as well.

The greatest benefit of coal halogen addition was reduced PAC injection rates (or the ability to switch to a less expensive PAC), and the associated PAC cost savings. A further economic benefit can be realized for plants that sell their fly ash for concrete manufacture, because lowering the PAC addition rate can allow the fly ash to be sold instead of landfilled. A further benefit of iodine compared to bromine is lowering the overall halogen load on the plant. This is achieved by either using much lower concentrations of iodine on the coal compared to bromine, and/or replacing bromine-treated PAC with a non-halogen PAC.

ABSORPTION OF MERCURY IN SCRUBBERS

Absorption of mercury in FGD scrubbers is one of the ways to remove mercury from the flue gas in coal-fired boilers. The solubility of $HgCl_2$ in water is relatively high and close to the solubility of HCl in water. The solubility of elemental mercury is 10^6 times lower.[5] The removal of oxidized

FIGURE 39: Reduced PAC usage for mercury control when using non-brominated PAC combined with iodine at addition rates of 3 to 7 µg/g on boiler with ESP.



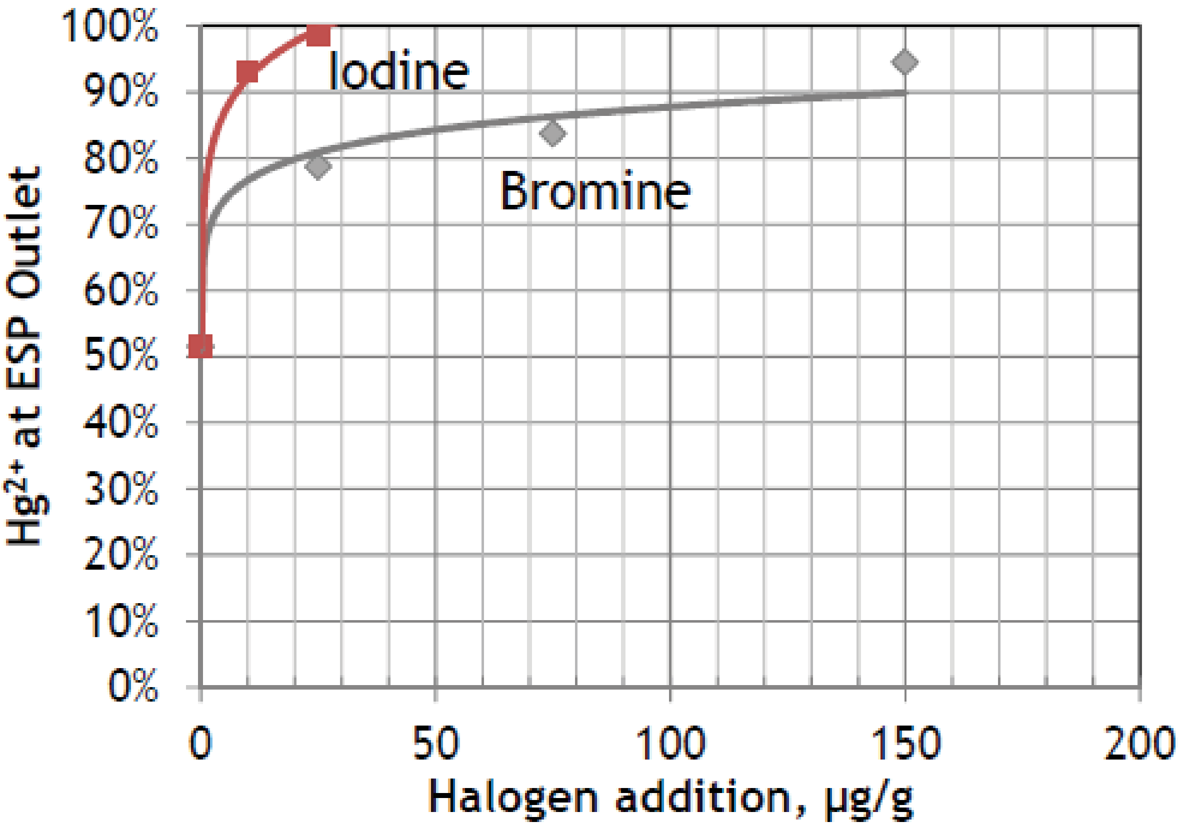


FIGURE 40: Fraction of oxidized Hg at ESP outlet of a subbituminous-fired boiler as a function of halogen addition rate.[4]

mercury by wet FGD scrubbers typically exceeds 90%.[6] In some scrubbers, however, some of the absorbed Hg^{2+} in the liquid is reduced back to elemental mercury, which has lower solubility and will be re-emitted at the stack. Therefore, a mercury control strategy that relies on a wet FGD to remove mercury must factor in techniques to mitigate re-emission such as managing scrubber chemistry through operations or by adding re-emission prevention chemicals.

RISKS ASSOCIATED WITH HALOGEN ADDITION

Plants within the first few years of utilizing halogens to enhance mercury capture, or considering halogen-based coal additives, must consider potential negative long-term impacts such as corrosion in the flue gas path, impacts to selenium partitioning that can affect wastewater treatment options and costs, and potential discharges of halogen in scrubber wastewater.

Several plants utilizing bromine for enhanced mercury control have experienced balance-of-plant issues. Because of operational issues such as corrosion being experienced at plants using bromine addition, EPRI initiated a study[7,8,9] on the balance of plant effects of bromine addition (including direct bromine addition and injection of brominated PAC). One hundred and eight coal-fired units using bromine addition have been surveyed through the ongoing study. EPRI has, to date, identified corrosion as the major observed impact. Sixty-four percent of units that added bromine to the coal prior to combustion observed corrosion, with 87% of these plants firing low-halogen western coals. Furthermore, 75% of the units adding any level of bromine to the coal and firing western coals experienced corrosion, most reporting air preheater corrosion, primarily at the cold-end of the baskets. At bromine addition rates of 150 µg/g Br on coal or above, corrosion was identified within one year. At rates of 100 µg/g Br on coal or greater, corrosion was typically noted within the first two years. The EPRI study also revealed that 81% of the units surveyed that injected bromine-treated activated carbon upstream of the air preheater experienced corrosion.

Iodine has been used as a coal additive, primarily in refined coal applications to treat more than 150 million tons of coal at treatment rates less than 5 µg/g I on the coal due to the improved effectiveness of iodine compared to bromine. No incidents of corrosion have been reported, thus no studies on

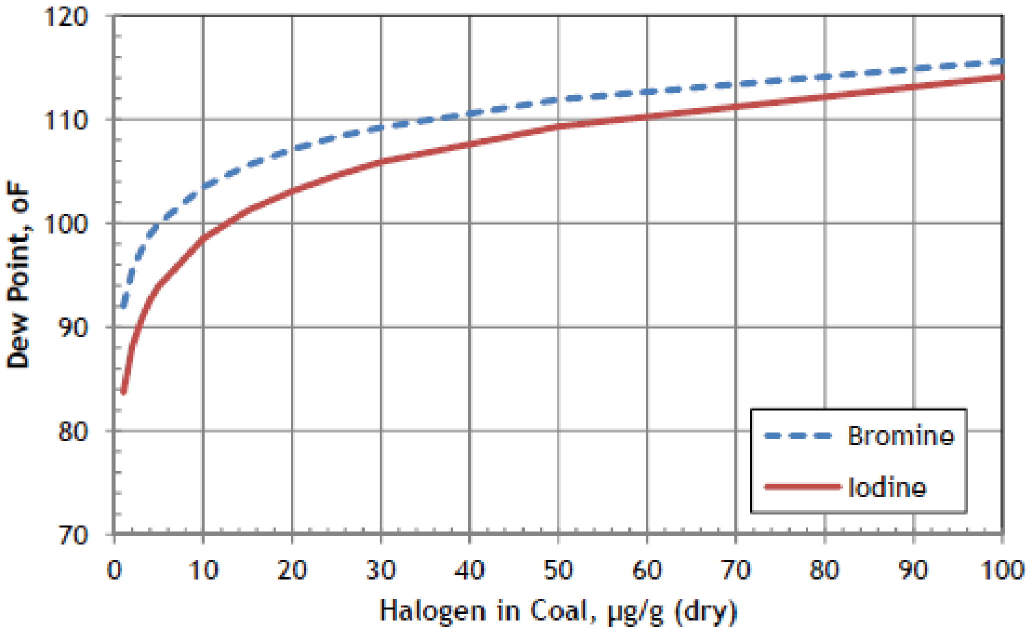


FIGURE 41: Dew point of halide species in typical PRB flue gas as a function of halogen addition rate to coal for 12.5% H_2O. (HBr dewpoint from Ganapathy[11]. Iodine dew point estimated by the authors from thermodynamic properties)

detrimental impacts have been funded to-date to compare to the EPRI study on bromine.

Recent results at both pilot and full-scale testing of corrosion rates using a real-time corrosion probe suggest that a hydrohalide condensation (i.e., dew point corrosion) mechanism is responsible for corrosion in flue gas at temperatures representative of air preheaters.[10] Calculations for typical concentrations of bromine addition indicate dew points[11] are in the 110-115 °F range for high moisture PRB coal (Figure 41) and bromine addition onto the coal in the range of 35 to 90 µg/g Br. Since typical iodine addition rates are about ten times less than corresponding bromine addition rates, the dew point temperatures associated with iodine addition are expected to be less than 100 °F, which is projected to be below typical cold-end metal temperatures experienced in air preheaters, even while operating at reduced load.

Another area of potential corrosion is in the wet scrubber. If halogens in the scrubber liquor are increased and the materials of construction were not designed for those increased halogen levels, corrosion could result.[12] In particular, scrubbers designed to operate on boilers firing Powder River Basin subbituminous coals, which typically have 25 µg/g chlorine or less, might not be constructed of the right materials for long-term operation with addition of halogens that increases the overall coal halogen concentration above design levels. Increase of halogens (chloride, bromide, etc.) in wet scrubber liquid discharge could potentially be a problem if the waters are discharged to a body of water with a drinking water treatment plant downstream. Although bromine is not included in the Federal Effluent Limitation Guidelines, permits limiting discharges that may contribute to formation of trihalomethanes (THMs) can be expected for select plants with sensitive downstream waters.

Plants with wet scrubbers should also be aware of potential risks associated with affecting the level of selenium entering their wet scrubber as a result of bromine addition. The addition of bromine compounds to the flue gas has been observed to increase the concentration of selenium in the flue gas downstream of the air heater[13] and in a wet scrubber slurry.[14] This correlation has not been observed for iodine. It appears that the presence of bromine compounds in the flue gas can result in a shift of selenium from the fly ash to the flue gas leaving the particulate control device. Increasing the concentration of selenium in the scrubber slurry might result in an increase in selenium in the FGD discharge stream. Selenium discharged with effluents from scrubbers is regulated in the Federal Effluent Limitation Guidelines, and the most oxidized form (Se[VI]) cannot be removed efficiently by conventional wastewater treatment units. Thus, a decision to add bromine to the system could result in a significant increase in the costs associated with wastewater treatment.

CONCLUSIONS

Addition of halogens to increase mercury oxidation in coal combustion flue gas is often included as part of a plant's mercury control strategy, especially for plants firing low-halogen western coals. Selection of the halogen species to add, and whether the halogen is added to the coal or as a treated activated carbon can have very longer-term balance-of-plant operational risk implications for the plant, and costs. When choosing or re-evaluating a control strategy, both the chemical costs and the longer-term risks should be understood and factored into ongoing operating decisions.

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Sharon Sjostrom is the Chief Product Officer at Advanced Emissions Solutions, Inc. where she is responsible for leading strategic product and business development for the corporation through its subsidiary ADA-ES, Inc. Sharon has over 25 years of experience developing technologies and commercializing products that reduce emissions from coal-fired power generation, with a focus on mercury controls. She has published more than fifty technical papers and is an inventor on sixteen patents.

Oxidation Air Rate Optimization and Control for Enhanced MATS Mercury Compliance

Written by Gary Blythe, PE, and Mandi Richardson, AECOM Process Technologies Organization

For the first 30+ years of operating experience with limestone forced oxidation (LSFO) wet FGD systems, the primary mission of the forced oxidation air system was to ensure that SO_2 removed from the flue gas was completely oxidized from the sulfite to sulfate form. However, since the implementation of EPA's Mercury and Air Toxics Standards (MATS), many LSFO wet FGD systems now serve as mercury control as well as SO_2 removal devices. To serve both purposes efficiently, the forced oxidation air rate should now be optimized to strike a compromise between these objectives. Modifications to the oxidation air system may be required to provide adequate turndown and control capability to implement this optimization.

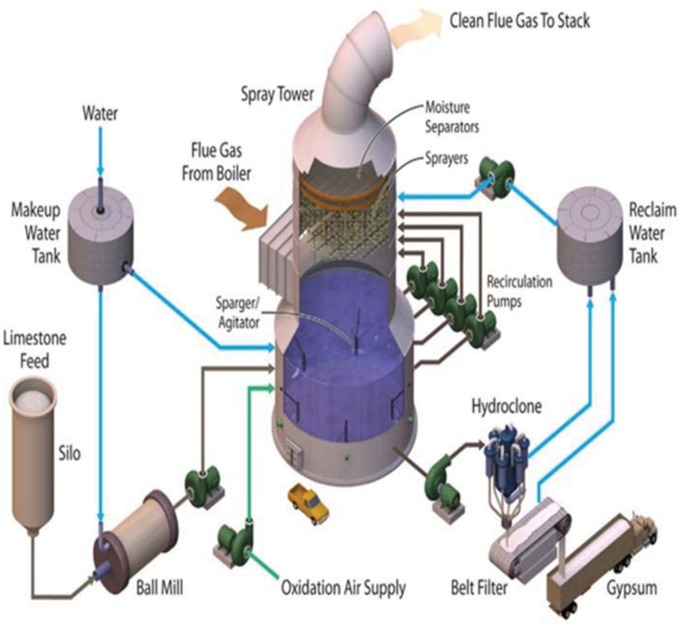

FIGURE 42. Simple Schematic of a Limestone Forced Oxidation Wet FGD System

BACKGROUND

In the past, there was generally no concern about adding too much oxidation air, within reason. Oxidation air systems typically were designed conservatively to ensure complete sulfite oxidation with the highest-sulfur design coal and at the maximum continuous rating of the boiler. Forced oxidation air systems were often designed with little or no turndown capability, and to this day many plants run their forced oxidation system at maximum air rates regardless of unit load or coal sulfur level. Previously this mode of operation produced no adverse effects other than maximizing energy consumption, but ensured that sulfite was completely oxidized, that slurry solids were well suspended in the reaction tank, and that oxidation air spargers did not plug.

Within the past decade, and particularly since 2015 when the MATS rule first went into effect, many LSFO systems have taken on a second duty – co-benefit capture of mercury from the flue gas. Co-benefit mercury capture has become the primary MATS mercury compliance strategy for many scrubbed, coal-fired units, particularly those that fire bituminous coals and are equipped with SCR. For this configuration, the chlorine in the coal plus the SCR catalyst lead to high percentages of oxidized, water soluble mercury in the flue gas (Hg^{2+}) which is readily scrubbed. Other units with different fuels and plant configurations also rely on co-benefit mercury capture by the wet FGD, in combination with oxidation technologies such as halide addition to the coal.

When a LSFO wet FGD system is used for co-benefit mercury capture, the rate of sulfite oxidation and indirectly, the forced oxidation air rate, have a significant effect on the net capture of mercury across the FGD system. Sulfite and oxidized mercury can participate in a reduction-oxidation (redox) reaction such that the sulfite is oxidized to sulfate and the mercury is reduced to the insoluble elemental form (Hg^0). The insoluble Hg^0 is released back into the flue gas, thus limiting the net effectiveness of the FGD system for mercury capture. The primary overall reaction that produces re-emission from FGD systems is believed to be as follows:

$$Hg^{2+}\ (aq) + HSO_3^-\ (aq) + H_2O\ (aq) \leftrightarrow Hg^0\uparrow\ (gas) + SO_4^{2-}\ (aq) + 3\ H^+$$

where HSO_3^- (bisulfite ion) represents absorbed SO_2 in an ionic form at lower pH. However, this overall reaction is actually the net result of a number of reactions that appear to be kinetically limited at many FGD conditions (i.e., they do not always proceed to chemical equilibrium). The kinetics of the re-emission reactions are quite complex, and many factors contribute to the rate of the overall reaction shown above, including pH, concentrations of chloride, bromide, iodide, and sulfite, among others.

CONTROLLING MERCURY RE-EMISSIONS

Many wet FGD systems used for co-benefit mercury capture rely on "re-emission" additives to limit the rate of this overall reaction. These additives function by removing oxidized mercury from the absorber slurry liquor such that it is not available to be chemically reduced by sulfite in an aqueous reaction. The additives are typically either chemicals containing a reduced form of sulfur, such as sulfide, which forms insoluble solid-phase precipitates or complexes with mercury, or activated carbon which adsorbs dissolved mercury from the liquor.

However, the authors and others have found that LSFO wet FGD systems can often be operated with little or no re-emissions by controlling the sulfite oxidation rate in the absorber reaction tank. There are two regimes where re-emissions are limited. One is where the oxidation rate is controlled such that some sulfite remains dissolved in the reaction tank slurry liquor, in the approximate range of 10-100 ppm. This regime typically corresponds with measured oxidation-reduction potential (ORP) values in the range of ~100 mV to ~300 mV (relative to a silver/silver chloride electrode). In this regime, re-emissions are limited in spite of having an abundance of dissolved sulfite available. The limitation is due to a transfer of dissolved mercury to the solid phase. This appears to occur by precipitation, adsorption or complexation with fine solids present in the absorber slurry, presumably a result of pyrite (FeS_2) being present as an impurity in limestone. It is not uncommon for more than 99.9% of the mercury in the reaction tank slurry to be found in the solid phase rather than dissolved in the liquor phase when operated at these controlled sulfite oxidation rates. However, as the sulfite oxidation rate increases and dissolved sulfite concentrations drop to non-detectable levels, this phase transfer effect diminishes and an increasing percentage of the slurry mercury remains dissolved, leading to re-emission.

The second regime is where sulfite oxidation rates are extremely fast, such that dissolved sulfite concentrations in the reaction tank slurry are well below analytical detection limits and measured ORP values are 600-700 mV or greater. In this regime it appears that sulfite is oxidized in the liquid film of the droplets as soon as SO_2 is removed from the flue gas, such that there is effectively no sulfite available to react with and reduce oxidized mercury.

However, operating in this highly oxidizing regime can have adverse effects related to other trace elements commonly present in FGD slurry. For example, under these conditions manganese, which often is introduced as a limestone impurity, gets oxidized to +3 and/or +4 valence states, forming insoluble manganese oxides that precipitate on absorber reaction tank walls. This can lead to under-deposit corrosion in alloy vessels. Also, selenium removed from the flue gas is completely oxidized to the selenate form, which is not readily removed from FGD wastewater by most physical/chemical processes and will require advanced technology to meet 2015 Effluent Limitation Guideline limits.

For these reasons, the authors believe that the first regime described above, with controlled sulfite oxidation rates and ORP values typically in the range of 100-300 mV, is the preferred mode for LSFO wet FGD systems used for co-benefit mercury capture. Many LSFO wet FGD systems naturally operate in this regime when the unit is at or near full load and when firing coal with a sulfur level near the FGD design level. However, when the unit operates at low load, fires a lower sulfur coal, or operates at low total dissolved solids levels, the design forced oxidation air rate is too great and more rapid sulfite oxidation occurs. This results in lower or non-detect dissolved sulfite concentrations, higher measured ORP values, higher dissolved mercury concentrations, and mercury re-emissions. Stack mercury concentrations are increased, often above the MATS 30-day-rolling-average limit.

VARYING OXIDATION AIR RATES TO CONTROL MERCURY RE-EMISSIONS

One way to deal with this circumstance is to add re-emission additives, or increase the re-emission additive dosing rate if additives are already in use. A more cost effective approach may be to lower the oxidation air rate so that the sulfite oxidation rates stay at the desired controlled rates, and both dissolved sulfite concentrations and ORP values remain in the desired ranges. Several approaches are available for controlling oxidation air to maintain controlled sulfite oxidation rates, including proprietary ORP feedback controls, dissolved sulfite monitors and associated feedback controls, or feed-forward control algorithms which consider unit load and SO_2 removal amounts.

However, many LSFO wet FGD systems are limited in their ability to turn down oxidation air rates to control sulfite oxidation. In some cases where oxidation air is used to provide agitation for reaction tank slurry or to keep from plugging fixed sparger grids, it may prove costly to implement changes to allow greater turndown. In these systems other variables may be adjusted in an attempt to slow sulfite oxidation rates, such as pH and L/G ratio.

In most FGD systems, there are a number of low-capital cost revisions to forced oxidation systems that can be implemented to provide greatly increased turndown capabilities. These can include:

- Piping changes to allow a single blower to provide forced oxidation air to two or more FGD absorbers at low air demand, particularly in systems where currently there is one blower per absorber with a common spare (Figure 43), and
- The addition of blow-off valves with silencers to provide additional turndown, while avoiding surging which can damage the blowers.

Other balance-of-plant upgrades may be required, such as:

- Installing in-line ORP meters,
- Installing in-line dissolved sulfite monitors,
- Upgrading manual valves in air systems to allow automated, remote operation,
- Upgrading oxidation air flow instrumentation with new equipment,
- Upgrades or revisions to oxidation air blower supervisory programmable logic controllers (PLCs), and/or
- Automating the control of forced oxidation air flow to each absorber through distributed control system (DCS) programming changes and new wire pulls.

Although these revisions, if needed, will require a modest capital investment to implement, they can greatly reduce or even eliminate ongoing O&M expenses for re-emission additives, and in some cases can provide a modest reduction in FGD power consumption. Other benefits may be realized such as less manganese scaling throughout the FGD system and lower selenate concentrations in FGD wastewater.

FIGURE 43. Forced Oxidation Air Configuration with Blowers Dedicated to Two Absorbers and a Common Spare

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BIOGRAPHY

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Mandi is a Senior Chemist and Project Manager in AECOM's Process Technologies organization. She serves as Principal Investigator or Project Manager on bench-, pilot- and full-scale research, development and demonstration projects. She also provides analytical chemistry support for laboratory and field projects conducted for the electric utility industry. Her areas of specialty include analyses of mercury concentrations in flue gas, solid and liquid media, and analyses of trace species in FGD byproducts and wastewater streams. She has a BS in Chemistry from Southwest Texas State University, and joined Radian International as a student intern in 1996. She became a part of AECOM after Radian was acquired by URS Corporation in 1999 and URS was subsequently acquired by AECOM in 2014.

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