CIBO Fluid Bed Conference
Raleigh Durham, NC
May 21 - 23, 2012

I. FBC Owners', Stoker Owners' and Equipment Suppliers' Forums

Reports From Individual Forums are Reported Below.

II. Review of Concurrent Forum Discussions – Gary Merritt, InterpowerPower/AhlCon Partners, L.P.

The first group to report was the Owner's group led by **Gary Anderson, Ebensburg Power Co.** The major concern was the Industrial Boiler MACT rule as well as other pending regulations. It was noted that on start up, the CO goes up very high when the unit switches from oil start up burners to solid fuel. They are concerned about meeting a CO standard over the entire load range. Even at 50% load, the CO goes up. Purdue is concerned about the HCl requirement under MACT. The chlorides are not absorbed the way SO2 is absorbed in a CFB. Potential options might include co-firing with gas. Sorbent injection may be a possibility, but the ash is being sent to a cement facility. The University of North Carolina has units that are multi-fuel capable (coal, oil, and gas). Turndown capability is down to 25%. The units are co-firing gas and coal at the moment. Low cost solid fuel may be a possibility for cost purposes.

The stoker group was led by **Bob Corbin, CIBO Consultant**. The results of the stoker survey were reviewed as well as the results of FBC survey conducted by **Jack Fuller of the University of West Virginia**. In the US, there are still half stokers and half fluid bed units on biomass. Only 5 units out of 378 indicated that they might be able to meet the Industrial Boiler MACT units. Only about 60 units out of 300 units firing biomass could meet the standard. The cost of compliance seems to be relatively high for an industrial unit. Reasons for downtime were heavily influenced by erosion. Biomass units seem to get a lot of sand, which causes erosion.

The equipment suppliers were led by **Monte Engelkemier, Stanley Consultants, Inc.** Discussions centered on the low price of natural gas. Cycling of existing solid fuel units is causing some issues with back end equipment and steam turbines where they exist. Opportunity fuels are being looked at to reduce costs. Switching to biomass has declined with the low price of gas and relatively higher price of biomass. For low pressure steam applications, a package boiler is probably the most cost effective approach. In terms of meeting the MACT rule, co-firing could be an approach to bring a plant that might be close to compliance. The value of fuel flexibility across fuels needs to be considered. Unfortunately, there is no silver bullet. Each case is site specific.

III. FBC Owner's 2011 Survey Results - Jack Fuller, West Virginia University

There were a total of 16 plants that responded to the survey. Half were larger than 70 Mw. There were a total of 30 boilers in the survey, one of which was a BFB, the remainder being CFBs. Fuel sources varied from coal, gob, culm, pet coke, and biomass. Secondary fuels include seed corn, wood, TDF, biomass, and other alternate fuels. Heat rates were somewhat better for the larger units. The Ca/S ratio ranged from 1.25 to 6.25. Fly ash utilization ranged from 54% for fly ash to 74% for bottom ash. Overall availability for coal plants was still better than 90%. Gob and culm fuels had a higher percentage of outage hours that were forced compared to coal. Forced outage hours were higher for newer units in 2011. Boiler related outage hours have held steady since 2006. There was no distinction for boiler outage hours for fuel or age. The top 3 causes were combustor pressure parts, backpass pressure parts, and turbine/electrical. O&M concerns were lead by pressure parts and tube erosion.

IV. EPA Overview of Regulatory Issues Impacting CFBs - Peter Tsirigotis, US EPA

The Boiler MACT rule is between proposal and final rule. The final rule is expected before the end of spring (ie sometime in June). The main comments that have been received have been on CO, solid fuel categories, combustor design based PM limits, gases other than natural gas, averaging for units that switch to natural gas, and total selected metals for liquid units. Additional data has been received on CO data and that has been factored into EPA's approach. For MACT rules, the process of making sub-categories is challenging and must have some technical basis. The comments have been more focused on technical issues at this point. The final rule has been sent to the US Office of Management and Budget (OMB). The OMB is charged with making sure that other agencies of the government have an opportunity for comment and input to these rules. Once this inter-agency review is completed, the rule will be issued and will subsequently be printed in the federal register. From the environmental group side, there is a recognition that this whole MACT process is a difficult one and that compliance will be difficult. This recognition is part of their learning process. Relative to the compliance deadline, typically the issuance of the new final rule in the federal register will start the clock on the compliance date.

V. FBC & Stoker MACT Performance Report - Amy Marshall, URS

The EPA database of units was reviewed to compare performance of FBC and stoker units against the proposed rule. The history of the development of the MACT rules is littered with law suits and vacatures. The current rule is on its third round and will still likely be litigated. The 2004 rule looked at the use of a control technology. The Brick MACT court decision basically threw out this approach. Rather, the rules are based on the average of the best 12% of units for which data is available. This resulted in a much more stringent rule, since many of these compounds show great variability in concentration of these trace compounds (mercury and chlorides). CO emission limits depend on the fuel and the boiler design. The CO limits for new units (at 19 and 17 ppm) are essentially not realistic as the limit must be achieved throughout the load range.

URS went through the database to look at the number of units that could comply. Biomass stoker units are close to the average level of 6%, with wet biomass units being a little higher and the dry biomass units being a little lower. The coal stoker units have only 1.3% of units that can make the standard.

URS looked at control systems that were in place for these units. For mercury, activated carbon injection, baghouses, and scrubbers were considered control technologies. The stack test data on these units is limited. The key issue is that most of the coal has mercury content greater than the limit (pretty much precluding a compliance fuel approach). Similar analyses were done for chlorides and particulate matter. Overall, there are few units that comply with all 4 rules. Coal stokers are particularly low. CO limits are problematic for many stoker boilers. PM limits are problematic for biomass wet stokers and coal stokers. HCl limits are problematic for coal stokers and fluid bed units. Mercury limits are problematic for coal units. The URS cost estimate for compliance is $14 billion, of which $4 billion for stokers.

VI. Regulatory Issues and Technologies to Comply
William (Bill) Campbell, AECOM Environment

Bill Campbell noted that some rules only apply to utilities and some that apply only to industrials and some that apply to all boilers. The "train wreck" slide (from AEP) demonstrates the number of regulations that are, or have been, issued that impact units. For utilities, the recently proposed GHG rule limits new units CO_2 to 1000 lb/Mwhr gross for all fuels. Peaking units are exempted. Since the best coal fired units are around 1800 lb/Mwhr, this rule effectively preempts new coal fired units. A good, clean, new natural gas fired combined cycle plant can meet this regulation at full load at ISO conditions.

The MATs rule is essentially the utility boiler MACT rule. This rule covers mercury, chlorides, and particulates. This rule is final, but is under litigation.

The CSAPR rule replaces the CAIR rule. This rule is aimed at ground level ozone improvements. This rule is expected to be finalized in the fall. The rule is expected to reduce SO emissions by 73% and NOx emissions by 54% over 2005 levels. This rule does not supplant the Title IV Acid Rain program.

Utilities also have to deal with water effluent guidelines. With wet scrubbers, there is additional potential for run off to contain additional materials. A new draft rule is anticipated in November 2012. This rule will likely drive plants to "zero discharge" operations.

For Industrials, there the Industrial Boiler MACT, the Area Source MACT, the CISWI rule (incinerator), and the definition of solid waste. The Boiler MACT rule is anticipated by the end of June. Dioxin/furans are currently treated with work practice standards. Startup/shutdown definitions are based on 25% load. Tune-ups are required on a biennial basis.

The Tailoring Rule for GHGs impacted units going through Title V or PSD permits. Construction projects and existing projects that emit GHG emissions of at least 100,000 ton/yr, or modifications that increase GHG emissions by 75,000 ton/yr will require permits. A top down BACT analysis for GHG is required for the permit. Biomass units have been given a 3 year deferment.

The NAAQS rules have been changing. The SO2 1 hour standard is now in effect and is 9 times more restrictive than the prior level. Modeling is being proposed by EPA, as opposed to monitoring. This has been challenged in the Courts. The 1 hour NOx standard is in effect and is 6 times more stringent than the prior level. There is a proposed 24 hour standard for PM2.5. The level is very close to background levels, which makes modeling difficult. The ozone standard was held at the 0.08 ppm level by decree. There was a proposal to go down to 0.07 ppm level. This level will be reconsidered in 2013.

The Regional Haze rule has triggered the first in a series of once per decade reviews of the impacts on visibility. This first review requires Best Available Retrofit Technology (BART). Compliance with the CSAPR rule is deemed to be in compliance with BART.

Water impact rules are becoming more stringent. The revised 316(b) rule is anticipated in July, 2012. Fish friendly devices will be needed for water intake streams greater than 125 million gal./day. Velocities must be less than 0.5 ft/sec. A rule was proposed for characterizing coal ash under subtitle C of RCRA (ie hazardous).

The rule is not final. There will be landfill liner requirements, lined ponds, and the elimination of wet ash sluicing.

The definition of an EGU is a unit that sells at least 1/3 of it power to the grid and is greater than 25 Mw. The type of fuel contributes to your classification or subcategory. Type of boiler creates sub categories in some cases. Major source and Area source definitions. To be considered a fossil fuel fired EGU, the unit must burn at least 10% of fossil fuel in the unit over the past 3 years. Once a unit has figured out which rules and emissions limits it has to meet, the controls to meet these standards must be considered. Traditional acid gas control systems for sulfur apply. Particulate controls include fabric filters, ESPs, and venturi scrubbers. Mercury control typically involves some form of activated carbon. NOx control includes SNCR, SCR, and hydrogen peroxide. SNCR is typically used for CFBs. There is a “regenerative” SCR which involves reheating the flue gas back up to SCR temperatures for proper reaction. Peroxide can be an additive for polishing the NOx level.

The sorbent injection panel included **Carl Laird of Carmeuse Lime, Curt Biehn of Mississippi Lime, Mike Atwell of Solvay Chemicals, and Jim Dickerman of Lhoist North America (Chemical Lime).** The choice between sodium or calcium additives will depend on the level of control required, the particulate collection system, and the potential beneficial use of ash. For most beneficial uses, the limitation on sodium is 2% in the ash. Water injection into the duct work has been frowned upon by plant managers/operators due to the tendency to over spray and wet the duct work causing corrosion. With adequate additive injection, dry sorbent injection can get reduction levels equivalent to dry scrubbers.

The equipment supplier panel included **Rich Miller of ADA, Carl Bozzuto of Alstom, Jim Connor of Clyde Bergemann, and Lauren Billheimer of Power Plant Management Services**. Equipment is available for mercury and chloride controls. Boiler exit temperature may be an issue for mercury control. The collection efficiency drops off quickly about 350 F. Baghouses and precipitators compete for particulate collection. For CO, only good combustion practice is available for coal fired units. For any unit, the CO will increase as the plant drops load. This needs to be taken into account in the regulations.

VII. Alternative Fuels Overview - Paul LeMar, Jr., Resource Dynamics

DOE had a program in alternative fuels that was spurred by high oil and gas prices in the mid 2000s. With the collapse of natural gas prices, the budget for such fuels at DOE has been cut. For solid fuels, often the comparison is against coal. Coal prices are highest in the Northeast and Southeast. Biomass was considered to be a potential alternative fuel. Urban wood waste runs about $15/ton. Crop biomass runs about $30/ton. Forest leavings and other residues add another $15/ton. At $30/ton only New England would support the use of biomass compared to the cost of shipping coal to New England. However, there is not that much coal use in New England.

Co-firing could be another approach. The rule of thumb limit would be 20% co-firing without significant changes in the ash behavior. If capital costs are involved, the payback is problematic. Even with low cost biomass, it is difficult to get a 5 year payback. Tire derived fuels depend on the availability of tires, the location of processing centers, and the shipping costs. TDF has a higher energy content than coal, but shipping tires involves shipping a lot of air as the bulk density is low. Petroleum coke supply is concentrated on the Gulf Coast. Domestic markets include cement kilns, pulp and paper, and some utility plants. There is also export demand for petcoke. As supply is located near water ways, barge shipping is possible (about $10/ton cost). The Southeast has the best opportunity to utilize petcoke compared to coal. The total economic potential utilization is around 250 million MMBTU/yr. Digester gas is an opportunity for gas fired plants. Treatment costs run about $1000/SCF/min. Pipelines cost about $330,000/mile. Landfill gas has similar costs. The total potential is 160 million MMBTU/yr. States with large population centers tend to have the larger landfills and better prospects. Industrial waste gas is a more limited opportunity. Coke oven gas is one opportunity, but there are not many coke ovens left in the US. The economic potential for all opportunity fuels was estimated at 420 million MMBTU/yr. (This would be enough fuel to support about 6,000 Mw at 7,000 full power hours/yr.)

VIII. Alternative Fuels Panel - Robin Ridgway, Purdue University

Bryan Ingram of Sega, Inc. reported on a University of Missouri BFB project. The university has 6 million sq ft of building space. The plant cogenerates 66 Mw. There are 5 boilers and 4 steam turbines along with 2 gas turbines and 2 HRSGs. The project expansion was to install a new BFB to replace an older CFB. The BFB would be 100% biomass fired. The primary fuel was woody biomass, with the possibility of corn cobs, stover, switch grass, and pellets. The biomass is available within a 50 mile radius. The biomass will reduce coal firing and resulting GHG emissions. Natural gas was considered, but price instability and the interruptible gas supply led to the choice of biomass.

Stokers, CFBs, and BFBs were evaluated for utilizing the biomass. With the selection of the BFB, the university was able to re-use the existing baghouse. Larger size pieces could be utilized. The fuel will be stored in silos with enclosed equipment to control dust. Biomass is low density, low BTU fuel. It is difficult to move and convey. Oversize conveyors are used to the transport the material to the silos. The steaming rate for the BFB is 150,000 BTU/hr. Over the roof of the plant, 18 Kw of solar panels are being installed. First fire is scheduled for August. The overall cost of the project is estimated to be $75 million.

Joe Marranca of the University of North Carolina reported on their project to test the firing of alternative fuels at the university power boiler. The university was an early signatory to reducing GHG emissions to nearly zero by 2050. A team was assembled to review a number of approaches to achieve this goal. A carbon action plan was drawn up. Land fill gas and coal substitution were two main approaches along with increased efficiency and programs from the electric utility. A team was then assembled to implement "teat burns" to evaluate the performance of these fuels. SEGA and AEI prepared the test burn procedure development. RST Engineering handled the air permit modifications. TRS did the stack testing. FW helped evaluate the boiler impacts. As the university is a state agency, the fuel had to be bid out, requiring a bid specification for the biomass fuel. Stack testing was required. Combustible dust and fire suppression concerns were addressed. Mill testing was carried out a Williams Crusher. A day bunker was used for biomass storage. The unit was a CFB. A gravimetric feeder was used for the wood pellets and conveyed pneumatically.

A 20 ton test was carried out first to demonstrate that the test could be done. Then the test procedures were developed and reviewed with the operators. Sampling protocols were developed. Three samples for each solid were taken during testing. The station performance system was used for overall plant data. Stack testing was done for mercury, HCl, NOx, SO2, CO, particulates, etc. As expected, boiler efficiency dropped off with increased with biomass. This is due to the increased moisture loss. With the alkalis that are typical with biomass fuel, the exit gas temperature increased leading to further efficiency losses. Higher excess air was measured. Baghouse cleaning cycles varied with load, but not with the addition of biomass. Agglomeration was not observed. There was no energy input calculation. The oxygen controller assumed the weight of fuel was coal, which accounted for the higher oxygen level. There was a large reduction in dioxin/furans and mercury. There were slight reductions in NOx, SO2, and particulates. HCl emissions increased.

Robin Ridgway pointed out that Purdue University has an evaluation process for alternative fuels. Many of the potential "fuels" can be eliminated on paper. Potential alternative fuel suppliers often don't understand the requirements of an operating power plant (permits, reliable supply, handling, etc.)

IX. Operation and Maintenance - John Malloy, IPAC, A/C Power

Steve James of Cambria Cogen pointed out that air flow measurements can be problematical. They run well for a while, but after 5 or 6 months there started to be some drift. Venturis were installed for dust laden flow streams. The key to these units is calibration. With improved calibration, the airflow accuracy was within 3% deviation to measured values. This improved the controllability of the two boilers. They actually operate in parallel with the new systems. The flow venturis are more expensive and have more pressure drop, but they are relatively low maintenance with minimal pluggage, erosion, and wear. Pitot tubes have a tendency to plug and wear. They require more maintenance. With the venturi unit, the pressure drop was 0.4 inches water gage at low load and 0.6 inches water gage at high load. The plant now does all of its own testing.

When the plant starts up, the venturi can be traversed to check the measurement. Using higher differential pressure over the calibration curve results in smoother flows and more reliable measurements. Static temperature and pressure are also measured in the venturi. The ability to calibrate when the boiler is hot gives are more accurate measurement of the flow. Overall, the plant has better control of the air flow, improved bed temperature control, better tracking of air leakage, and parallel operation.

Howard Moudy of National Electric Coil reported on generator outage planning and execution. Outages should be planned. Then the plan has to be executed and followed up with results. Common maintenance issues include contamination (air cooled in particular), dusting (parts grinding against one another), greasing (oil leaks sucked into dust), partial discharge (spark ionizes the air causing nitric acid), spark erosion, and end winding resonance/looseness.

Preliminary planning involves knowing your machine, specifications, a qualified "bull pen" of suppliers, and an understanding of how your equipment works. There are still good places to get information. The purpose of the specification is to clearly to define the expectations and requirements of the project. The best time to develop specifications is before you need them. Past reports should be consulted for valuable information. The basic templates are for test and inspect, stator rewind, stator coil manufacturing, and rotor rewind.

Knowing that a machine has certain issues (from past reports) should provide direction for the types of tests that should be run. Temperature is one of the basic reasons for damaging the insulation and eventually the core. Testing the core includes the current flow and the loop test. The loop test runs the exciter to 90 - 95% of its rated flux. Side packing is a critical component to the corona protection system. Testing protocols should be coordinated from coil final test through in process testing to final machine acceptance testing. IEEE has standards for testing levels. Bump testing checks for local and global natural frequencies near the 120 Hz double operating frequency. Resistance losses are inversely proportional to the copper area. Eddy current losses are proportional to the strand thickness. The circulating current losses are related to the voltage potential difference between the strands. Fit up inspections should check the clearance. Proper lead alignment is critical to final brazing operations.

For rotor rewinds, the copper can be reused provided it passes the hardness check and the cleaning and reshaping protocol. Retaining ring evaluation should determine whether the ring is magnetic or non-magnetic. The non-magnetic rings are susceptible to stress corrosion cracking. These rings need to be kept dry. After a rewind, the high speed balance verifies the balance and overall "operability" of the rotor. Bushings are the most overlooked components on the inspection list.

Terms and conditions are necessary today. If handled before the need for an inspection, more or less standard T's and C's can be obtained. Emergency communication information should have the basic information about the machine including nameplate information, site location, and design specifications.

Randall Dooley of Kenametal reported on wear protection measures. One process is called conforma clad. This puts a Tungsten Carbide coating onto a substrate material. The largest annealing furnace is 24 ft long and about 4 ft wide. The erosion resistance compared to carbon steel is roughly 1/16 inch of the cladding equal to 3 inches of carbon steel. The bond strength is 10 - 15 times most spray coatings. Conforma Clad has been in power plant applications for about 15 years. High wear areas in the plant include slurry nozzles, panels, in bed tubing, fans, and SCR screen materials. The material has been applied at the TVA Shawnee bubbling fluid bed application. All of the evaporator tubes have been replaced with this material since 2003. At Seward, Conforma Clad was used after the spray coatings wore away. Nose tubes were replaced at Greenberg Thermal. These have been in operation for 20,000 hours with virtually no wear. Stokers burning MSW have successfully used the material in high chloride environments. Anthracite culm plants have shown more wear than anticipated. It is recommended that a test specimen be installed first to determine expected life. Burner tips can also make use of this material. Coal piping can also make use of the material.

Don Halulko of CBP Engineering reported on choosing the right wear materials. There are a lot of wear materials. However, selecting the wrong wear material for your application may be worse than no selection at all. There is no "app" for this selection.Wear materials include epoxies, plastics, urethane, rubber, steels, AR steel, basalt, ceramics, silicon carbide, tungsten carbide, and others. The types of abrasion include sliding abrasion and impact abrasion. Understanding the application and the material will lead to a successful solution.

X. Update and Insights on Ash - Lisa Cooper, PMI Ash Technologies

In 1980, the Bevill Amendment to RCRA prevented EPA from regulating ash as a hazardous waste. The amendment required a periodic report to Congress. Several reports to Congress confirmed the original position. The Kingston power plant impoundment failure released 5.4 million cubic yards (1 billion gallons) of ash slurry. This incident changed the ground rules. EPA has proposed 2 major options for future regulation. These are Subtitle C (hazardous waste) and Subtitle D (non hazardous waste). The primary justification for Subtitle C was to enable federal enforcement authority. Beneficial use of coal ash was to be exempt from regulation under both scenarios. Under RCRA, joint and several liability would apply and the stigma of hazardous waste designation would pretty much kill beneficial use. The Anti Coal Environmental NGOs include Earth Justice, Environmental Integrity Project, Sierra Club, Public Employees for Environmental Responsibility, and others. Pretty much everyone else does not want the ash declared a hazardous waste.

EPA is now in a box. They can't go to Subtitle D because of their allegiance to eNGOs and they can't go to Subtitle C due to international and industrial pressure. In Congress, HR 2273 was passed in the US House. A companion bill in the Senate was filed in October (S1751). Coal ash provisions are now included in conference committee negotiations of the transportation bill (HR4348).

In the meantime, EPA is conducting its own risk assessment without public input. Twelve environmental groups sued EPA to review RCRA requirements every 3 years. Two coal ash marketers have also sued EPA seeking public transparency. Minefilling has been targeted by the eNGOs as a non-beneficial use. Rulemaking is under the Office of Surface Mining. Site tours have been conducted. At this point, there has been no apparent activity. PMI recycles coal ash into concrete. The ash can be treated before going to the cement plant.

XI Introduction to Chemical Looping - George (Geo) Richards, USDOE

Chemical Looping provides an opportunity to capture CO2 at relatively low energy penalty (about 4% compared to 20% for amine or oxygen firing). The DOE is a working with a number of entities on this process, including Alstom. The DOE is looking at a number of applications in the industrial area. These include EOR, small boilers, food grade CO2, hydrogen production, and others. DOE is also looking for a small demonstration application. DOE is building a small test facility at NETL.

XII. Back End Control Technologies - Gary Merritt, Interpower Power Ahl/Con Partners

Peter Ristevski of Macrotek reported on gas cleanup optimization for FBC and stoker boilers. **Macrotek** provides custom designed, wet scrubbers for use with boilers. Sulfur in the fuel mostly ends up as SO2, with a small amount of SO3. The halogens in the fuel, such as chlorides, end up as the acid gas, ie HCl.

For SO2 control in a fluid bed unit, calcium in the form of limestone is added to the fluid bed. The bed temperature is optimized to utilize as much of the limestone as possible, while still meeting the capture requirement. As the capture requirement increases, a higher Ca/S ratio is required which reduces limestone utilization. Polishing scrubbers can be used to increase the level of sulfur capture without excessive calcium addition. Polishing scrubbers can also capture the halogens in the form of acid gases. A polishing scrubber can be added after the ID fan. This approach allows for independent optimization of the primary capture level in the fluid bed and the capture level in the polishing scrubber.

It is possible to combine the scrubber into the lower portion of the stack. Reagents can be calcium based, sodium based, or waste alkaline material. The sodium based system is the simplest, but the reagent is more expensive. However, with a polishing scrubber, the amount of capture is relatively low compared to the capture in the bed, which minimizes the amount of reagent that is needed. With a sodium system, a packed bed scrubber can be used. Removal efficiencies are 99+%. Materials of construction can be fibre reinforced plastic (FRP), stainless steel, or lined steel. With calcium based systems, an open spray tower is used with multiple banks of sprays. Paper mills often have waste alkaline streams that have to be neutralized for disposal. The waste stream can be used as the reagent. If necessary, a final polishing tray using sodium can be utilized to get to the final capture level required.

John Vaklyes of Midwesco Filter Resources noted that the list of back end equipment keeps on growing as the regulations keep on ratcheting down. Limited space at most facilities puts additional stress on the duct work arrangement at the plant. System concerns include type of fuel, type of boiler, flue gas temperature, flue gas chemistry, fly ash properties, available plant area, and the presentation of the gas stream to the components. For duct design, carrying velocity, mechanical stiffeners and supports, elbows and turns, turning vanes, and connecting points all impact the design and layout of the duct. Internal structures should be minimized. However, turning vanes may be required in order to provide a reasonably consistent flow pattern to a given component.

Instrumentation locations are also important. Flow stratification or rotation tends to bias the flow as well as the measurement. A fabric filter is a “dumb machine”. It only reacts to what and how material is presented to it. Membrane bags offer higher throughput, lower emissions, and longer life. Off line cleaning will allow for lower overall pressure drop, lower compressed air cost, and longer bag life. Off line cleaning can help in lime and activated carbon utilization. Offline cleaning of a membrane bag will provide 95% cleaning of material on the bag. Back end equipment is now critical process equipment.

Tony Silva of B&W presented on dry sorbent injection for acid gas control. Dry sorbent injection can provide enough capture to meet regulatory requirements. SO3 capture may be needed to protect the activated carbon system for mercury control. SO3 is preferentially absorbed onto activated carbon and swamps the capability of the carbon to capture mercury. Chloride capture is required for both utility and industrial MACT.

Trona, sodium bicarbonate, sodium carbonate, and hydrated lime are all potential dry sorbents. Truck delivery to a hopper is the typical installation system along with pneumatic delivery piping. For some additives, a mill is required. Good sorbent to gas contact is required for good performance. CFD modeling is used to provide guidance to the design. Physical modeling was used to validate the computer model for lance performance and duct runs.

The temperature ranges for most of the sorbents runs from 300 - 500 F. SO3 is readily absorbed. HCl is also readily absorbed if there is no competing SO2. The fabric filter after injection helps to provide additional capture. Capture rates are typically around 80% for SO2, 95% for HCl, and 98+% for SO3.

For ESPs, there are a number of questions that need to be addressed. ESP performance can be impacted by resistivity changes and ash parameters. Ash sales can be impacted by the additional sodium in the ash. Sorbent utilization is impacted by particle size, residence time, and sorbent penetration and mixing. For sodium sorbents, a milling system will serve to reduce the particle size in order to reduce the amount or sorbent required. Pin mills and air classified mills can be used. Air classified mills will produce a finer particle size with a much tighter particle size distribution.

Roger Leimbach of Metso Power and Automation provided information on controls for biomass boilers. Biomass is not homogeneous. The fuel handling system is a critical component. Fuel variation and stoppages contribute to adverse changes in steam flow, pressure, and output. Typical control systems do not have a good means of dealing with fuel variability. Measuring the energy input is difficult. Proper fuel sizing is critical. Distribution of the air is also important as air staging is needed for control of NOx and CO. The energy balance approach (developed by Combustion Engineering and Sulzer) can provide a means of addressing the fuel variability. Stored energy needs to be taken into account.

At steady state, energy input equals energy output. When load changes, some energy either goes into or out of storage in the system. Measuring the heat release (the derivative of the change in drum pressure) provides a means of addressing the variability in fuel characteristics. For stokers, several levels of overfire air are used. The impact on CO and NOx is different at the different levels. Therefore, controlling the overfire air is important. When demand changes, the energy requirement changes. Dynamic compensation accomplishes the amount of overfiring or underfiring needed to increase or decrease load. For a fluid bed boiler, oxygen consumption has some errors, but has the advantage of being a very fast measurement. A heat balance requires averaging but is relatively slow. By putting the two functions together, a better control of fuel and air flow can be obtained. In doing so, bed temperature is more stable as well as emissions levels. The reduction in variation of performance provides an overall reduced emission level.

XIII. Monitoring Systems - Gary Merritt, Interpower Power Ahl/Con Partners

Brian Conway of Sick Maihak reported on particulate, mercury, and HCl monitoring systems. Particulate monitors can now be used rather than opacity monitors. Many instruments come in either EPA compliance or non-compliance versions. For wet gases (after wet scrubbers) a probe style system is used. For relatively dry gases, a scattered light system is used. There is also one monitor with both opacity and particulate in the same device. This is cross stack transmission system. In one utility installation, the data showed considerable spikes in concentration. It turned out the ESP was experiencing some issues and tuning the rapping sequence cut way down on the spikes. As a result, the actual overall emission levels were reduced by 50%.

The most difficult part of getting a good analyzer is setting up the analyzer properly. At a wood fired plant, the SCR catalyst was experiencing problems due to high dust caking on the catalyst. A similar issue with the ESP was uncovered. Resolving the ESP issues improved the overall emissions, the catalyst performance, and the caking problems on the catalyst.

For mercury monitors, there are requirements for waste to energy and cement plants. Power plants will be needing these systems. A probe system is used for the measurement. The analyzer catalyst requires shade protection. The sample line length should be kept to less than 150 meters. There are no moving parts in the analyzer. Maintenance is usually higher for mercury monitors. Currently, the system is certified in Germany for 3 months maintenance free based on 6 months testing. The system has applied for 6 month certification based on one year testing.

The sample system heats the sample to 185 C. The basic principal is atomic absorption spectroscopy. Mercury is an atom rather than a molecule. Thus, electron emission is needed rather than molecular activity. A magnet is used to amplify the activity and focus the emission. A photoelastic modulator and a polarizer are used to get a reference beam and a sample beam. In this manner, interference from SO_2 can be eliminated. Self calibration and zero drift are incorporated.

At a waste incineration plant, the new device was installed side by side with an existing monitor. The existing monitor had to use a 3 minute average. The new device gave continuous monitoring. The 3 month maintenance interval was achieved. A similar installation was done at a cement kiln.

For HCl measurements, several technologies can be used for measurement. Technique is important for this measurement. Hot and wet are the best conditions for HCl measurements. High velocity is also a good practice. Absorption and desorption problems with HCl are involved with all of the technologies. A hot, wet, extractive system can measure NO_x, NH_3, SO_3 and other gases as well as HCl. With the multi extractive system, the cost is higher.

If only HCl was to be measured, a tunable diode laser spectroscopy system can be used. There is a sample system and a cross stack system. Two types of probes are available, one with a ceramic filter and one without. At another waste incinerator plant, a new monitor was installed side by side with a 20 year old monitor. The two gave identical results. The old system was getting more difficult to maintain (electronic parts). An FTIR system can also be used for HCl measurement, along with about 10 other gases.

Jeremy Whorton of Thermo Fischer Scientific reported on their CEMS systems. A mercury monitor works like an SO2 monitor with a NOx sampling systems. The temperature requirement for the sample line is 158 F. The sample is diluted and the mercury oxidized. Then the sample is run through a “race track” in order to separate particles from the gas. A portion of the gas is drawn from this sample with the rest going back to the stack. Then a “black light” is used to make the final measurement. Calibration is done by using a cell with mercury in it. A gas is passed through the cell to evaporate the mercury into the gas. A number of large utility units have installed monitors. Values typically range from 7 - 10 micrograms/m3. There was one installation with a CFB. The mercury level was 0.2 microgram/m3.

Cement plants are beginning to use these monitors. The cement plants run a little differently. Those with raw mill preparation run with low mercury when the mill is on and then a very high level when the mill is off. With the number of gases to be measured, there is a desire to have one probe with multiple measurements. An FTIR system can provide this. For particulate matter, both fore scattered and back scattered light can be used. One difficulty is that the measurement is indirect. The other is that water drops will show up as particulate.

An oscillating micro balance can be used to calibrate the system. The microbalance weighs a sample and passes it through a filter. The material on the filter represents the weight of the solids. This method has been certified as equivalent to Method 5. Periodically a sample from the gas stream is sent through the oscillating balance and used to calibrate the instrument. For HCl, an FTIR probe can be used. The FTIR measures other gases as well. At a cement plant, NOx, CO, oxygen, moisture, ammonia, and HCl were measured. The criteria measurements werecomparedtotheFTIRwithgoodagreement.

Phillip McMaster of Altech USA noted that industrials don’t necessarily have to use a CEMs system. A stack test can be used. However, states may require CEMs and eventually such systems will become standard. For particulates, a beta guage technolgy can be used. A paper tape is used as a filter for the particulates. A beta source is used as a supply and a Geiger counter is used to pick up the reading, The amount of particulate on the tape attenuates the beta signal. For mercury, sorbent trap systems can be used. Moisture measurement can correct to dry condition for EPA reporting. A probe at the stack is used to pick up the mercury. A signal goes to the cabinet on the ground. Since moisture is measured, there has to be a drain for the water.

The trap system is cheaper than a CEMs. Maintenance includes replacement of traps, rebuilding pumps, and normal cleaning. FTIR is used for HCl. This system uses a small sample volume with a small flow rate. For sample conditioning, moisture should be removed from the sample as soon as possible with no production of droplets. HCl will be absorbed into the water and escape measurement. A SEC (dry in French) probe extracts the moisture using a membrane and very dry air. Once the sample is dry, a dry sample line at 185 F takes the sample down to the analyzer.

XIV. Tour Overview–Phil Barner, University of North Carolina-Chapel Hill

UNC has a cogeneration facility about a half mile from campus on 11 acres. The steam supply comes from two plants with 5 boilers, two of which are CFBs. Total capacity is 1.15 million lb/hr of steam. There is one 34 MVA steam turbine. There is an electric distribution system with 5 transformers and 3 substations. The chilled water supply has 5 plants with 50,000 tons supply. The CFBs produce the steam for the steam turbine. The steam supplies heating and humidification, along with steam for the absorption chillers. Steam is distributed through undergroundpipingtotaling45miles.

Tim Aucoin described the plant. Coal is delivered by rail. About 12 cars can be stored on site. There are two coal silos for storage along with an emergency pile. Fuel oil is used for back up fuel. There is a 3 cell cooling tower. All distribution lines must be underground. As a state institution, the university cannot sell power. Steam to the campus goes at 150 pis and 40 psi. The university is on an hourly pricing structure with the utility (Duke Power). The university has a marginal cost of about 6 cents/Kwhr. When the Duke pricing is higher than the marginal cost, the university generates its own power. When the Duke pricing is below the marginal cost, the power is purchased. The plant is permitted for multiple fuels including natural gas, coal, and biomass. There are two day bins for coal. The combustor runs at about 1600 F. The plant has a tubular air heater and a baghouse. The plant has been recognized by the EPA for superior environmental performance. Unit operation runs from a low of 70,000 lb/hr to 250,000lb/hr.

Carl Bozzuto