CIBO's Fluidized Bed XXIII Conference
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I. Reports from the Owner's and Suppliers' Panels - Bob Bibb, (Bibb Engineers, Architects & Constructors), Facilitator

Harvie Beavers, Colmac Clarion, Inc. reported on the Owner's Panel including John Thalhauser (Archer Daniels Midland Company) Gary Mell (Michigan State University), and Van Strahan (Georgia Pacific). The owner's concerns this year were especially directed towards the regulatory environment. Uncertainty over the regulations and the economy make it extremely difficult to make decisions. The owners are hoping that the suppliers are making developments that can help meet some of these new standards. Michigan State would like to burn more wood for CO2 reasons. They are part of the Chicago Climate Exchange and have some obligations. However, they would be moving into unknown territory in terms of emissions and chemistry. They have some chemical deposit that has not been identified that condensed on the windows of their monitors during a test burn. Harvie noted that the small IPPs are typically under fixed price contracts. With the economic crisis, the price for electricity that is now being offered will make it difficult for these small IPPs to renew or renegotiate their contracts.

Ray Ganga (McBurney Corporation) reported on the Suppliers' Panel including Bill Campbell (AECOM), Carl Bozzuto (ALSTOM), Phil McKenzie (B&W), and Gene Christiansen (Metso). The major concern was the tidal wave of new regulations being issued. The cost of just answering the questions that come about during the permit process has increased expotentially. In many cases, data is not available for the fuels and operating conditions in question. Sustainability has been a watch word for several environmental groups. The cost of plants is going up as more compounds are being regulated. This is a political issue. The politics of these projects are very important. Not only local support, but state support is important to line up before going for a permit.

One of the owners asked about having problems with NERC (National Electric Reliability Council). This plant has had a person on site for nearly a year. Another owner noted that they were audited and had to pay a fine for missing a battery check. The concern is that this will be another agency that is looking to grow their own bureaucracy.

One university noted that there now may be a greater willingness to try a "serial number 1" project to resolve some of these issues. He noted that if someone had an alternative to a polishing scrubber for chloride control on a CFB, they would be willing to try it. Of course the issue comes down to guarantees. These cases may lend themselves to alliances or partnerships to get projects done.

II. 2009 FBC Owner's Survey Results - Jack Fuller, (West Virginia University) and Carmine Gagliardi, Air Products & Chemicals

Each year, CIBO asks its members to complete a survey on their fluid bed units. The data is then sent to Jack for compilation and analysis of the results. This year a CIBO team headed by Carmine Gagliardi was formed to assist with analysis (Gary Merritt, Harvie Beavers, and Gary Anderson). The forms are now posted on the CIBO website to make it easier to fill out and submit. The presentation will be posted on the CIBO website.

This year, 18 plants responded to the survey with a total of 32 boilers (28 CFB and 4 BFB). Over the years, the plants have gotten larger (12 of 16 > than 40 Mw). The fuel sources included 10 coal fired units, 5 gob fired units, 1 culm, and 1 wood unit. Three plants used secondary sources of wood, biomass, and natural gas. The average Ca/S ratio was 3.7 with a range of 1.6 to 8.4. Fly ash utilization was practiced by 44%. Bottom ash utilization was practiced by 58%. Over 40% of the units are looking at addressing the new mercury requirements in the Industrial Boiler MACT.

Over the years, gob fired units have had the best availability (about 95%). The average availability for the rest of the units was about 90%, although the coal units had somewhat lower availability. The average outage hours that were the result of forced outages were about 30%, although there was a spike to 40% for the gob units in 2009. This result may be due to plants going to an 18 month planned outage cycle. With higher availability, the number of forced outage hours becomes a larger percent of the fewer outage hours. The causes of forced outages included combustor pressure parts, fuel handling/feeding, ash handling, turbine/electrical, refractory, load restrictions, cyclones, and others. The largest contributor was combustor pressure parts (tube leaks). Major concerns included ash regulations, fuel quality, ash handling, and fly ash. This result is new, resulting from the new regulatory proposals. Technical issues moved down the list of concerns.

III. Regulatory Panel

Bill Campbell (AECOM) reviewed some of the key provisions of the new rules. The Industrial Boiler MACT has 11 categories, including biomass. If any solid waste is burned, the unit will be classified as an incinerator and will fall under the CISWI (commercial and industrial solid waste incinerators). Both the Boiler MACT and the CISWI will be published in the Federal Register on June 4th. Comments are due in 45 days. The final rule will be issued Dec. 16, 2010.

Kathy Blue of Trinity Consultants reported on EPA's approach to New Source Performance Standards and New Source Review for CO_2 emissions. EPA has issued the Tailoring Rule in order to "minimize" the number of units or facilities that would be impacted by EPA's approach to regulating CO_2. The EPA endangerment finding became effective January 14, 2010. This lead to the EPA light duty vehicle rule which became effective May 7th, 2010. Since this is a control standard, this rule triggered the PSD and Title V requirements for sources that emit more than 100 tons/year of CO_2. This would impact over 6 million facilities. EPA issued the Tailoring Rule to raise the limit for GHGs to 75,000 ton/yr. The first step begins Jan. 2, 2011 (coinciding with the light duty vehicle rule). If a unit already triggered PSD, it will now have to consider GHG emissions.

There is a major modification threshold for a project that would increase GHG emissions on a CO_2 equivalent basis by 75,000 tons/yr. The second phase starts July 1, 2011 and includes the first phase units. Units that are not major sources for another pollutant, but will emit CO_2 on a 100 ton/yr of CO_2 or 250 ton/yr of all GHGs on a mass basis or the potential to increase GHG emissions by 100,000 ton/yr. There is a step 3 that may begin July 1, 2013 that would look at lower levels. The rule provides for an exclusion level of 50,000 ton/yr for a 6 year period. These units that are designated major sources for GHGs will have to utilize BACT for GHGs to get a permit. Right now, BACT for GHGs is efficiency.

In order to facilitate state and local implementation, EPA will give states 60 days to comment on how they will interpret "subject to regulation". EPA will issue a FIP to assure that the rules are interpreted consistently. There are six major sectors that will become the focus of these rules, including power/utility and industrial boilers. There is not likely to be a NAAQS for CO_2. Thus, modeling will not likely be required. At this point, there are no PSD exemptions (i.e. biomass is included). Permit streamlining is based on potential to emit and presumptive BACT. BACT guidance is planned to be issued in the fall of 2010.

EPA is not amending Title V regulations for fees at this time. There are a number of legal challenges to these rules. One of the issues for these challenges is that a stay of the Tailoring Rule would fall back to the 100tpy/250tpy rules in the Clean Air Act. Energy efficiency will likely be the standard. This could be as simple as a lb/CO_2/MWhr standard or lb CO_2/lb steam standard.

Gary Anderson, (Ebensberg Power) reported on regulatory compliance costs, with emphasis on the cost of "proving" that the unit is in regulatory compliance. In Pennsylvania, new requirements for monitoring ash handling and disposal, as well as fee increases, have put more costs on the power plant. The Ebensburg plant burns bituminous gob in a CFB that was installed in 1991. The ash is returned to the mine site for beneficiation. The waste pile is mined and portions are then reclaimed using the ash from the boiler. The Revloc Refuse Site has been reclaimed. The stream beside the site had a pH of 2 before reclamation and is now a trout stream.

Compliance costs include the costs of fees, permits, and expenses to demonstrate compliance, but does not include the cost of operating the equipment to meet the regulations. Major regulatory programs include, Title V, RACT, Emissions Allowance Programs, CAIR, CAMR, NERC, and Homeland Security. All of these rules added new reporting requirements. Significant cost adders include CEMS upgrades, stream characterization studies, clean air funds, mine site permits, enhanced water monitoring, higher DEP fees, and ICRs. There have been 3 ICR tests (at about $50 K each). Since 1992, the cost of compliance has nearly tripled. By contrast, the inflation rate has increased 60%, while the price of the electricity produced has increased only 20%.

IV. Alternative Fuels Panel - Robin Ridgway, (Purdue University), Moderator

John Thalhauser (Archer Daniels Midland Company) reported on co-firing of biofuels at ADM's Cedar Rapids CFB. Archer Daniels Midland Company has 10 cogeneration plants that burn a variety of fuels. Biomass fuels are used extensively. In the processing of corn, about 40% of the manufacturing costs are related to steam. As a 100 year old company, there are a number of types of boilers including PC units, cyclones, hybrid stokers, conventional stokers, bubbling beds, circulating fluid beds, and gas fired package boilers. There are also a few gas turbines. The largest CFBs are at 1.2 million lb steam/hr.

The Cedar Rapids cogen plant has 5 units dating back to the 1980s. The company plans to burn about 360,000 tons of biomass/yr. Jason Freeman (Archer Daniels Midland Company) reported that corn stover, seed corn, and dried water treatment sludge are the sources of biomass at the plant. The dried sludge has a heating value of 8500 - 9000 BTU/lb. This is blended with coal to about 40% dried sludge. The dried material is dusty and somewhat abrasive. A number of systems were evaluated to move the fuel. A pneumatic system was selected to unload the fuel and an L-path conveying belt was used to move the fuel to the boiler.

Under manual control, the O2 was erratic resulting in some O2 spikes. Coincidentally with the O2 spikes were some SO2 issues. Automation of the boiler controls greatly reduced the swings. Somewhat less drying of the sludge is also being considered. The seed corn results from discarded corn from suppliers, corn from flood contamination, and other discarded seed. The material tested in the dried sludge facility was fairly messy and did not work very well. The limestone system has worked better. No corrosion or deposition has been observed in the 2 years of operation. A separate unloading system with metering will be installed in order to get a better estimate of the heating value being fed to the unit.

Corn stover has been tested. Two 5 day tests were planned with stover at 10% of the fuel load. Four 6 inch pipes were added through the front lower secondary air piping. The initial test was halted due to binding of the air lock. The stover "ratholed" in the truck. The first test was cancelled. With some additional equipment, the second test processed 798 tons of stover. The grinding system provided tramp material. The wet stover tended to plug the bag houses on the silos. Considerable bridging in the storage and handling systems occurred. In the boiler, the bed temperature drops slightly (10 - 15 F). The temperature at the top of the furnace tended to increase as the light material carried up. Dried and ground stover did not appear to be economical. Pelletizing might be an approach to enable the use of this fuel.

Carmine Gagliardi, (Air Products) reported on their Stockton Cogen Plant in Stockton, CA. The plant was started up in 1988 under the California Standard Offer #4 (in response to PURPA). The unit originally used 100% coal. Pet coke and TDF has been added. The TDF represents 5% of the heat input. The pet coke is 30 - 50% of the heat input. The unit is a 60 MW gross output system. The fluid coke is received pneumatically. TDF is received via "walking floor" trailers. The TDF is mixed with the crushed coal and stored in silos. The unit is permitted for up to 11% TDF. When the first PPA ran out, biomass was considered as a fuel. California is pushing for 20% renewables. California also has CO_2 regulations (1100 lb CO_2/Mwhr).

There are site constraints due to being surrounded by other entities. Challenges include material handling and storage, ash properties, and variability. Walnut shells, almond shells, and pistachio shells were the first fuels tried. The ash is sent to the orchards for soil treatment. Combustion issues include slagging, agglomeration, chlorides, and ash properties (due to SNCR).

A phased approach was planned. After initial testing, a staged level of biomass quantities would be utilized. Initially 8 - 10% biomass was fed to the boiler. Today the level is 20 - 25%. Phase III will be at the level of 50%. This level might be achieved in 2012. The prices of these fuels varies greatly. Walnut shells started out at $8/ton. The use of the shells for sand blasting caused a price increase to $40/ton. Currently the plant is buying the shells at $25 - 30/ton. An off site biomass storage system is being utilized.

Coordination with the coal deliveries was critical, as existing equipment had to be used for both fuels. About 10% of the biomass in storage is lost to wind and birds. Currently, trailers are used to bring the biomass to the site so that some fuel is stored on site. This makes the coordination with the coal feed considerably easier. The nut shells are the right size for the boiler. Flowability and self heating have not been a problem. Performance has been demonstrated to 35%. There is a slight derate of output with the biomass (lower heat content than coal). There has been no impact on ash properties.

For phase III, a new on site receiving system is planned. A new system will be designed for woody biomass. The off site storage will be maintained as these fuels are seasonal. Orchard prunings are being considered. The fuel tends to be stringy and will need to be screened before use. Variability of the fuel, particularly with respect to alkalis raises concerns about the slagging potential of these fuels. The phase III startup is planned for May 2012. At 50% biomass, the plant would be under the 1100 lb/Mwhr of CO2 in California. About 25 Mw of "green power" is being delivered to PG&E.

Bob Bibb, (Bibb Engineers, Architects & Constructors) and Ray Ganga, (McBurney Corporation) presented some experiences with alternative fuels. Biomass is quite variable. While wood and walnut shells are relatively low in ash, rice hulls and barley needles are up to 20% ash. Moisture contents vary considerably. All of these fuels are different. Start with the fuel and then determine the technology to address it. Waste incinerators to burn sewage sludge have been used routinely. In the early 80s, waste heat boilers were added to one of these facilities to generate some steam. At that time, there were no CFBs in operation in the US. Early CFBs in Europe were burning peat, wood, and RDF.

V. Operations, Maintenance, and Optimization - John Malloy, AC Power Colver

Steve McCaffrey, (Greenbank Energy Solutions) reported on controlling limestone feed/bed distribution for improved utilization. The group has developed a family of flow distributors that have been trademarked as VARB(TM) (variable area rope breaker). The system breaks the rope of solids, homogenizes the flow, and equalizes the splits in two phase material flow applications. The technology resulted from a joint venture with two universities in the UK (Leicester and Nottingham). A two phase flow rig is used to validate designs. The design problem requires the plant's material distribution data which is then modeled with CFD (Fluent). The existing distribution is simulated to predict the position of a "rope". The actual position of the rope is validated. Then a VARB(TM) design is simulated in position in the model. The optimum position is then located and the new piece is installed in the plant.

Not all designs will work. The CFD model screens out the systems that do not work. The preferred design is then installed. The test rig is about a 1/3 scale system that can simulate a wide variety of plants. The rig can be operated over a wide range of velocities and loadings. At one plant, the original configuration produced a 70/30 split in a "T" splitter. The rope breaker brought the distribution to close to 50/50 (48/52). Basically an adjustable splitter plate in the line up to the "T" was installed where the fuel line split. These plates are all alumina refractory lined. At another plant, an ABB controller, (PF Master), was installed for flow control. The addition of a rope breaker allowed the flow controller to better control the flow.

Steve Storm and Adam McClellan, (Storm Technologies) reported on combustion airflow measurement and control on CFBs. Air flow measurements are important for both operation and testing. Air, fuel, and gas flow distribution needs to be measured and controlled for optimal operation. These are all related to the fuel. High CO levels on start up are often caused by improper air flows on start up. Independent measurement of air flow to the grid plate, the feeders, and the secondary air. High furnace temperatures are due to air flow stratification and can lead to fouling. For the overall efficiency evaluation, flow measurements throughout the plant are needed. An on-line, air in-leakage measurement system has been developed.

The flow paths in a CFB include front upper secondary air, front lower secondary air, rear secondary air, total hot secondary air, primary air to the grid, total hot primary air and start up burner primary air. Sensing tap size and location is important to avoid pluggage. Venturi systems are used for flow measurements with 3 inches pressure drop across the venturi. Flow traverses at 3 different flows are used to calibrate the system and develop the flow constants. Balancing the system resistance to the air flow to the grid nozzles can help assure more uniform air flow to the grid. Ideally, the air flow to each secondary air port would be measured.

Fred Farabaugh, (AC Power Colver) reported on the air and limestone optimization case study at their plant. The Colver plant is a 102 Mw plant with a permit to 111 Mw. The Pyropower CFB produces 785,000 lb/hr feeding an MHI turbine with 2400 psi/1005 F steam. The waste coal exhibits a considerable amount of variability. The boiler has 2 cyclones. Limestone utilization and optimization was combined with air flow improvement to improve plant operations. Limestone consumption was high and, at times, emission levels could not be met, resulting in curtailments. Maintenance costs for the limestone system were increasing. Supplemental limestone was brought in by truck for the periods of higher sulfur fuel or high maintenance days. Total evaluation of the limestone supply system was carried out. Reduction or elimination of conveyance piping and elbows. Some limestone is now mixed with the fuel. Monitoring of the limestone entering the unit improved overall control of the limestone.

Gravimetric feeders were recommended for limestone feed. These have been rejected due to a lower return on investment than other changes. The piping system was simplified and streamlined. The system pressure drop was reduced. The limestone usage was reduced by 30%. The subsequent maintenance was reduced (more uniform velocities and lower limestone flow).

Air mixing inside the boiler is essential for complete combustion of the fuel. Air in-leakage prior to the air heater results in a heat rate penalty as well as a control problem. A variety of test ports were installed throughout the system to analyze air leakage. Original test ports were re-opened and additional test ports were added to help determine air flows, temperatures, and chemical compositions. At the last outage, heavy material was noticed primarily on one side of the boiler. Tramp metal was also recovered on that side. Testing indicated that the air measurement system was reading 30% high. The secondary air flow measurements indicated there was a flow unbalance (low air on the side with the heavy material).

Ben Fish, (University of Iowa) and Sean Gordon, (Clear View Monitoring Solutions) reported on the use of a multivariate computer model to detect tube leaks in a CFB. The university uses 170,000 lb/hr of steam at peak. The plant does not have an engineering staff. The goal was to develop a computer system to look back through the data acquisition system to try to determine if there are any relationships between or amongst the variables. By looking at these cross correlations, it is possible to find some data points that are outside normal operation. For a tube leak, the superheater steam side temperature difference and the gas temperature difference will show that cooling is happening in the gas flow due to a steam leak. The system also picks up the difference between steam and water flow. For turbines, bearing temperatures, oil temperatures, and other temperatures are monitored for leaks or failures. A demonstration of the software was available at the ALSTOM Power, Inc. booth.

Phil McKenzie, (The Babcock & Wilcox Company) provided a comparison of fluid bed technologies for renewable energy. The common question is, “What is the technology for biomass”? The answer is always that it depends on the fuel and the site. One customer wanted to use the same type of unit for plants in the Pacific Northwest and the Southeast. The only restriction was that the technology had to be fluidized bed. The customer also wanted to be a minor source. The turbine would be a 50 Mw machine using steam at 968 F and 1754 lb. The fuel would be virgin woody biomass.

B&W evaluated both bubbling bed and CFB technology. The normal emissions levels were similar for both systems. However the chloride limits would require the addition of dry sorbent injection. The NOx emissions required by the customer would have likely required SCR on the bubbling bed with only SNCR for the CFB. There were advantages and disadvantages to each design. The SCR is an added expense, but the ammonia useage was less. The combustion efficiency was higher for the CFB but the parasitic power was higher. Both designs were carried out. Life cycle cost estimates were done on both systems. The BFB with the SCR came out with the lower overall, life cycle cost.

This case was driven by the fuel choice (virgin wood) and the low NOx requirement. If coal (or pet coke or waste coal) was part of the fuel mix, the CFB would be advantaged.

VI. Absorbents - Gary Merritt, Inter-Power/AhlCon Partners, L.P.

Heidi Davidson, (Solvay Chemicals) reported on dry sorbent injection of sodium sorbents. There are two main sodium sorbents: trona and sodium bicarbonate. The trona is a naturally occurring substance called sodium sesquicarbonate. There are numerous beds containing billions of tons. The majority of the trona is mined to make sodium bicarbonate. The sodium bicarbonate is essentially baking soda. It is made from sodium carbonate by CO2 absorption. When injected into a furnace, these carbonates are “calcined” to sodium carbonate which reacts with SO2 and SO3 to make sodium sulfate. These compounds can also remove HCl and HF. A number of industries including cement, ceramics, metals, and chemicals use trona for this purpose.

Trona is also used to scavenge SO3 ahead of mercury removal systems using powdered activated charcoal (PAC). SO3 competes with mercury for sites on the PAC. Even ppm levels of SO3 tend to swamp the ppb levels of mercury. Test results show that SO3 scavenging of SO3 allows the PAC to be effective for mercury. As long as the temperature is above 275 F, acid gas removal will occur.

The injection systems are generally low capital cost investments. Stoichiometric ratios range from 1.5 for sodium bicarbonate and 2.5 of trona. Heavy metals such as arsenic and selenium tend to be captured by the sodium and end up in the ash.

Howard Fitzgerald, (Lhoist North America) reported on calcium based sorbents. Limestone is heated to liberate CO2 and generate lime (CaO). If the lime is treated with water, it makes calcium hydroxide or hydrated lime (slaked lime). The lime or slaked lime can re-absorb CO2 to become limestone again. Municipal solid waste combustion plants in Europe were looking for a material to control acid gases. Lime based products were developed with high surface areas to absorb these gases. For HCl and HF, high capture efficiencies could be obtained with stoichiometric ratios of 1.5 -2.0. The absorption occurs in a 2 step process.

The first step, taking one HCl, is fast. The second step, taking a second HCl, is relatively slow. The final product is CaCl2. Dry lime injection has been used in the US for SO2 reduction. Heavy metals reductions are being tested. High temperature (1500 F) for SO2 capture has been tested. Another calcium based product is being developed for dioxins and furans, as well as heavy metals. This material has a mineral additive as well as the hydrated lime.

Carl Laird, (Carmeuse) reported on the use of lime kiln dust in CFBs. Lime kiln dust is a material that comes from a lime kiln in the production of lime. The dust is not as pure or as high quality as the product lime. At an earlier plant test, the LKD was added using the existing limestone system. The LKD is finer than the limestone, which did lead to some handling issues. At a second unit, the LKD was blown into the silo with the pulverized limestone and injected by the same ports. About 5,000 tons of LKD were utilized. No additional modifications were needed. The LKD was more efficient than the limestone. At a 3rd facility, dolomitic limestone dust was blown into the silo with the limestone. This plant is still using the LKD. At a 4th unit, 2 tests were conducted. In one test, the LKD was injected directly from the truck into the back pass. In the second test, the LKD was injected into the furnace. LKD can be utilized with existing limestone systems. The pH of the ash will increase. The LKD is more effective than limestone.

VII. Coal Combustion By Products - Gary Merritt, (Northern Star Generation)

EPA began a draft proposal to regulate CCBs in early 2009. A draft was submitted to the OMB in October. The rule at that time would only apply to utilities and EGUs. The OMB requested comments from several Federal Agencies. OMB asked the EPA to respond to comments and concerns raised by the other agencies. The National Governors

Association met with the OMB to express their concerns. On May 4th, the EPA proposed an alternative approach. This would have the potential for subtitle D or subtitle C (hazardous waste). All of the other agencies stated that subtitle D was far superior to subtitle C regulations.

In either case, EPA wants to get rid of wet systems and impoundments. EPA listed 27 damage cases. However, these cases involved dam failures, wet CCR systems, and impoundment discharges. The differences between the proposed rules in terms of requirements are small. In order to be "federally enforceable", the rule would have to be under subtitle C. To remedy that situation, citizen action suits can be brought against the states for not enforcing the federal program under subtitle D. EPA is soliciting comments for management of CCBs, risk assessment, liners, beneficial use, and stigma. Under each issue, EPA has identified numerous questions, for which they seek input. A revised draft rule will be issued in June.

VIII. Backend NOX, SOX, and HAP panel - Gary Merritt, (Northern Star Generation)

David South, (SPE-Amerex) reported on air emission compliance solutions for FBC units. The company was formed by the merger of SP Environmental and Amerex in 2004. Solutions to compliance issues include concepts beyond the equipment, including allowance sales, offsets, green energy credits, etc. At a waste to energy plant in Hawaii, an ESP system is being replaced by a baghouse. In order to minimize down time, the project is being staged so that one baghouse is built while the unit is still operating. This first baghouse is cut in while the ESP is being dismantled. Then the second baghouse is built and cut into the system, allowing the unit to run at some load during that operation. Dry scrubbing systems are being used for sulfur capture. Both rotary atomizers and nozzle atomizers are offered.

Rich Miller, (ADA Environmental Solutions (ADA-ES)) reported on the use of activated carbon for mercury and dioxin control on fluid bed boilers. ADA provides carbon injection systems and is now building one of the largest activated carbon production plants in the country. Activated carbon has been used on incinerators and cement kilns and is now being used for PC and stoker units. ADA has about 50 units in operation. They have also tested CFBs. The best results for carbon injection are obtained when a plant has a baghouse. ADA is starting to inject their additive ahead of the air heater to increase the residence time of the material when an ESP is being used.

Trona is being used to reduce SO3 for those applications that have higher SO3 levels. The SO3 competes with the mercury for capture sites on the carbon. Looking at the industrial database, out of the top 12% performers in mercury levels, 33% are fluid bed boilers. This equals 84% of the CFB fleet. The CFB with a baghouse should be able to meet the MACT rules for mercury. The top 12% of dioxin performance indicates that more units will need to add some kind of controls. The Seward CFB (waste coal) has reported high levels of native mercury capture (over 95%) with activated capture injection. The JEA and Sandow CFBs reported "non-detect" levels of mercury. The Sandow unit was required to have an activated carbon system, but it probably was not needed for mercury alone.

The Dominion Virginia City Hybrid Center is a 330 MW unit under construction utilizing waste coal and wood. Demand for activated carbon is projected to reach 1 billion pounds/yr. Establishing a baseline is key to determining what needs to be done and what impacts the proposed control systems will have on the rest of the plant. Compliance grade mercury CEMS are recommended. CFD modeling is recommended for analyzing the injection locations and types of lances.

As MACT compliance is currently projected to be December 16, 2013, testing and evaluation needs to start within the next year. Allowing for system design, procurement, installation, and performance testing, it should be possible to meet the compliance date. However, the Utility Boiler MACT is coming out later this year. This will put additional pressure on the suppliers.

Peter Honeycutt, (Kiewit Power Engineers) reported on dry CFB scrubber technology. Kiewit did a study for a utility in the Northeast in the last year evaluating these technologies. The dry or semi dry systems include spray dryer absorbers (SDA), CFB scrubbers, and NID (new integrated desulfurization) systems. The SDA system uses a slurry of lime to be sprayed into a spray dryer. This requires a slaking system to slurry the lime. The CFB scrubber was developed for the aluminum industry for HCl removal. Pebble lime is slightly hydrated with the addition of 3% spray water. The product is still handled as a dry material. A tall column is used to contact the flue gas and the solids. A baghouse is used to capture the solids and recirculating them (hence the CFB nomenclature).

Units up to 330 MW are in operation. A 420 MW unit is under construction in Europe. Most of these units were added to CFBs as polishing units. However, the larger units are being put on PC units. The NID technology being offered by ALSTOM utilized a flash dryer absorber (FDA). A special humidifier is being used to carry out the hydration of the circulating solids directly. Kiewit visited units in the US and Europe to learn about these systems. Common features are materials of construction, multi-pollutant removal, dry residues, dry stacks, and baghouses. The pros for the CFBs (including NID) are EPC costs, no slurry limitations, dry additive (no slurry), independent injection of lime and water, high SO2 removals (98% SO2 removal on a 6 lb/MMBTU fuel), lower horsepower, lower maintenance, able to use low quality water, and no double handling of ash. The cons for the CFBs are larger and elevated baghouses, nozzle changeouts, and small US experience list.

Jay Crilley, (NALCO Mobotec) reported on NOx and SOx reductions on two 173 Mw CFBs. Mobotec offers ROFA and Rotamix systems for CFB systems. Measurements at the cyclone inlet indicate that CFBs have relatively poor lateral mixing. The ROFA system utilizes rotating opposed overfire air. The ROFA system causes a rotating flow. The Rotamix system is an SNCR system. These systems were installed at the Twin Oaks ALSTOM's CFBs. The ROFA mixing increased SOx reduction. At these units the outlet SO2 was reduced by 55% (210 ppm down to 94 ppm). The CO was reduced from 586 ppm to 117 ppm. The Ca/S ratio has been reduced from 2.7 to 1.5. At a Ca/S ratio of 2.5, the 90% reduction was improved to 95%. At a constant 90% SO2 reduction, the Ca/S was reduced by 28%. The Rotamix system was installed to reduce the Nox. The inlet to the cyclone was modeled to understand the mixing at that point. The NOx level was reduced by 71% with an ammonia slip of 2.4 ppm (133 lb/hr NH3). The carbon in the ash is also reduced.

IX. Plant Overviews - Steve Cooper and John Kang, JEA and John Vonnoh, Rayonier

Steve Cooper, (JEA) gave an overview of JEA's 300 MW CFBs at their Northside Generating Station. Northside produces roughly 30 - 40% of JEA's total output. The original design was set at 297 MW. Current output is now up to 315 MW. These units replaced the existing oil fired units. The steam turbines were upgraded at the time of the CFB installation. The units burn coal and pet coke. The overall project for both units and the turbine upgrades was $630 million, including permitting. The US DOE contributed $72 million. The unit achieves 98% SO2 removal and 0.11 lb/MMBTU NOx. The unit has a polishing scrubber. This repowering doubled the station output while reducing emissions by 10% over the existing unit.

The start up experience went through a number of incidents including Intrex back sifting, cyclone pluggage, and stripper cooler problems. The steam cooled cyclone was designed to reduce the weight of the cyclones (from refractory lined). An SDA system is used for the polishing scrubber. Fuel is delivered by barge and conveyed across a wetlands area to the boilers. A shed has been added to the limestone prep area to keep the limestone dry at all times. The fuel prep building contains the crushers. There are twelve feed points (6 front and 6 rear). During start up, the bed temperature was low. About 50% of the division walls were removed. The Intrex and cyclones experienced plugging. Some of the surface in these areas has been removed. The stripper cooler experienced plugging and refractory failures. Expansion joints have been a problem. The reheat temperature was too high. There was also back sifting through the air nozzles on the grid plate.

John Kang, (JEA) gave an overview of their latest project to resurface the boilers. The initial "improvements" were reactions to "urgent" problems and in many cases were not completely successful. The follow up improvements, based on improving fluidization, were not completely successful either. JEA has a six sigma program. These techniques are being applied to these units. They were having problems making steam temperature. A regression analysis showed that bed depth and pressure drop in the Intrex heat exchanger were the two key parameters. By gaining better control of the air flow to the Intrex heat exchangers, the heat pickup in the Intrex came under control. Stabilizing Intrex performance allowed for stabilization of steam temperatures. After this experience, they applied similar techniques to the scrubbers, the stripper cooler, fuel and limestone prep, and CFB optimization.

They are currently working on the furnace surface analysis and modification. The furnace outlet temperature was as high as 1820 F. After the last outage, the output has increased and the furnace temperature was reduced to 1740 F. Steam temperature has been stabilized to 1000 F. Now that the units are operating in a reliable mode, the next step is to optimize the heat transfer surface. Tube surface modifications will be based on the results of thermodynamic modeling. They are now targeting 1650 F at the cyclone inlet. Operating temperatures in the range of 1750 - 1800 F have resulted in premature tube failures and ash pluggage.

JEA is using PEPSE software for the thermodynamic modeling. They have their own CFB simulator. The tube installation will be done under JEA supervision. There are division walls, wing walls, and Intrex tubing. There are also stripper coolers that remove and cool the ash from the bed. After looking at all the possible changes, roughly 66 combinations were identified per load. These were narrowed down to 4 options that were further explored at more loads and other fuel combinations. The combination that was selected was to add 2 wing walls, 12 division tubes, and a full Intrex bundle. These modifications will be made in the fall of 2011. The payback is expected to be less than 1 year. The hard savings are ammonia and limestone. The soft savings will be improved availability and reduced maintenance costs.

John Vonnoh, (Rayonier) gave an overview of the Rayonier FBC unit at the Fernandina Mill. The project concept was to replace 3 old boilers from the 1930s with a used boiler that would be modified to accept BFB technology to be relocated to the Fernandina site. The unit would have an ESP and SO2 scrubber added. The old units burned oil and bark. Reduction of oil use was a significant driver. There is a chemical recovery unit on site to burn the black liquor and recover the cooking chemicals. With the new BFB unit, the oil used has been reduced by more than 90%.

A boiler from a closed paper mill was available in the Jacksonville area and included the fans, pumps, conveyors, water treatment, piping, spare parts, and scrubber. The steam conditions are 900 psi and 850 F. The unit was slightly derated for the BFB firing system. There were 4 other boilers under consideration, but the Jacksonville unit was the closest unit and the nearest to their design requirements. The BFB design was selected with view towards being able to burn TDF and other alternative fuels besides bark.

The project was installed in 10 months. Sand is used as the bed material. The slumped bed height is 2 feet and the operating bed height is 3 feet. The total emissions have been reduced by 50% over the 3 old boilers. The project paid for itself in less than 3 years.