CIBO Fluidized Bed XIX Conference

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Hershey, PA

I. Fundamentals of FBC Combustion – James (Jim) F. Desellem, Babcock & Wilcox Company

There are two types of fluid bed combustors, bubbling beds (BFBs) and circulating beds (CFBS). B&W uses the fixed carbon level to decide when to use BFBs or CFBs for industrial sized boilers. For the BFB, the bubbling bed acts like a firing system and is comparable to a burner system or a stoker. Once the flue gas leaves the bubbling bed, the boiler doesn't really know where the flue gas came from. For the CFB, the bed material is circulated throughout the combustor and the solids collection system. There may also be a fluid bed heat exchanger. There are several ways to capture and recirculate solids in a CFB including a hot cyclone, a cold cyclone, or other type of mechanical separators (u-beams, c-channels, louvres, etc.). In bed heating surface practice in the CFB include horizontal panels (omega tubes), wing walls, and full length panels.

The heart of the BFB is the bubble cap. The bubble caps provide even distribution of air to the bed. The BFB handles low NOx by staging combustion (as well as the lower bed temperature). The overfire air provides up to 65% of the combustion above the bed. Thus, the lower air flow goes underneath the bed. Thus, the bubble caps need to provide even distribution of air to handle the substoichiometric combustion. The bed temperature can be controlled with a combination of air flow and flue gas recirculation. An open bottom floor system allows oversize particles to escape from the bed. The open bottom can also tolerate tire cord and other wire type ash material that needs to escape from the bed. Up to 30% of the heat input can be from tire chips.

The CFB normally uses a flat floor with a standpipe for a bed drain that is connected to the ash removal system. A water cooled screw can be used for oversize ash removal. If the ash content is very high, a fluid bed ash cooler can be used to recover some of the energy remaining with the hot ash.

The key to good fluid bed operation is bed material management. Good fluidization provides lower emissions, lower agglomeration potential, better heat transfer, and better combustion. The spent bed material retards fluidization and should be removed via a drain system. Screening of drained material can provide for the recycle of good bed material back to the system, while separating the oversize materials. Lack of control of the bed material can cause loss of control of the bed, leading to agglomeration, high temperature differentials, combustion in the back pass, etc.

When retrofitting existing units to BFBs, the plan area that is required for the bed is typically larger than the existing unit. Means to open up the bottom of the unit is required. For biomass materials, a sand type bed is needed to provide bed material. Care must be taken to avoid shocking the silica by having it cycle between bed temperature and air temperature.

II. Equipment and Service Suppliers' Forum - Lou Gonzalez, B&A Inc., Engineers - Facilitator

One of the issues from owners has been about selection of fluid bed equipment for various applications. Perhaps some kind of guidelines could be prepared to help owners get started in this process. There have been a lot of requests to increase steam supply capacities while reducing costs and emissions. There are a number of considerations including footprint, space, fuel, emissions, etc. that drive the various choices.

Starting with fuels, there are wide ranges in price even on coal depending upon the quality of the fuel. The opportunity fuels have restrictions on shipping and ash properties. While fluid beds can burn a wide variety of fuels, a fluid bed plant needs to be designed to handle the worst quality fuel that is specified. Simple considerations such as the quantity of ash (determines ash handling capacity), the heating value of the fuel (determines the fuel feed capacity), and moisture level of the fuel (determines the gas weight and volume of the flue gas) are critical. A boiler system designed for low moisture fuels will not have the fan capacity or the velocity capability to handle a high moisture fuel. Particle size control is absolutely critical to bed operation. At the time of selection, the fuels that are potentially desired for use should be specified so that any design compromises can be made. Opportunity fuels have a number of issues including variability that must be taken into account during design.

Permitting issues also impact design considerations. In many cases, projects are developed and promises made about emissions and then fuels and equipment are to be selected. This approach can lead to disconnects in permit requirements and equipment performance. **A** sequence issue results -- Is it better to close in on fuel selection and work with a manufacturer for performance and then try to get a permit or to go for a permit and then try to get performance from the suppliers? An iterative process is likely required as issues are revealed during these activities. In front of all of this, the owner needs to know what the boiler is needed for (base load, back up, swing load, process steam, etc.). This needs to be clearly communicated to the suppliers (engineer, boiler supplier, materials handling, controls, etc.).

Once the project requirements are known, the fuel matrix needs to be defined. This includes all of the characteristics of the fuels including ash characteristics, materials handling, particle size, emissions, etc. There will likely be some iteration required on these items since there are potential unit sizes or fuel choices that could reduce the need for some kinds of equipment. Limestone testing and characterization are needed to assess emissions performance as well as the corrosion characteristics of the resulting ash. Erosion issues can also be a problem for waste coals and other poor quality fuels. Ash disposal methods and costs also need to be considered. Back end equipment that may be required need to be evaluated. Once these have been identified, the permit requirements need to be evaluated.

A further iterative process will likely be required until a reasonable project can be permitted in full and equipment specifications can be written. The goal is to get a realistic permit that reflects realistic operations. Flexibility is critical in this regard. A number of projects never got built because the permit conditions were unrealistic and financing could not be obtained as the guarantees, etc. would not support the financing.

Overall project schedules are getting longer (material deliveries, project issues, permit issues, etc.) and costs are increasing (commodity prices, labor costs, environmental costs, etc.). In the current environment, there are now limits on the number of lift vehicles, the number of welders, the number of boiler makers, etc. Construction schedules are impacted. Commercial considerations also play a role. Partnering is one way to overcome some of the traditional adversarial positions in putting together some of these projects.

III. 2005 FBC Owner's Survey Results - Jack A. Fuller, West Virginia University

Jack Fuller presented the results of the latest survey of the CIBO FBC owners looking at benchmark type information. For this year's survey, an attempt was made to identify units of similar size, fuel, etc. in order to create an average performance. A total of 22 plants responded to the survey. There were 7 in the 1 - 39 MW range, 9 in the 40 - 99 MW range, and 6 in the 100 MW or larger. Roughly 1/3 of the plants used a secondary fuel source in addition to the primary fuel. There were a total of 30 boilers in the survey of which 26 were CFB and 4 were BFB. A total of 21 bench marks relating to operation including staffing, heat rate, availability, outage rates, capacity factor, etc. Data was collected into averages for each group.

For the benchmark of full time employees per million man hours, small units showed a definite trend toward reduced man hours for operation. Age data indicated that 13 units were installed pre-1990 and 17 units were installed after 1990. For certain benchmarks, the data was broken out for age. Roughly half of the respondents are evaluating mercury for Boiler MACT. About half of the respondents are subject to the NOx trading program. Of those that responded to the type of reagent for NOx control, 36% used aqueous ammonia and 64% used anhydrous ammonia. Outage causes still show turbine and electrical, tube erosion, and fuel feeding/handling as the main causes of outages. In anticipation of 2006, highest concerns were fuel quality, fuel handling, and tube erosion.

IV. Owner's Forum Panel Report – John S. Hall, Panel Leader, Inter-Power/AhlCon Partners, L.P.

The panel members were Peter Kline (P.H. Glatfelter Company), Philip Jones (Scrubgrass), John Oelbracht (Jamestown Board of Public Utilities), and Jack Fuller. Several items were brought up during the owner's discussion including backpass fouling, fuel handling, and limestone utilization. Units that have been utilizing waste sludges have been experiencing more fouling. The type of fouling was a red terra cotta material that was very tenacious. Mechanisms of formation might include cementing, eutectic formation, and agglomeration. Michael Virr of Spinheat Ltd. pointed out that the addition of kaolin clay to sludge has provided relief from these types of deposits. Water lances on shut down have also been used to remove these deposits.[1.]

[1.] A copy of an old (19--) paper would be provided for the conference CD by Michael. See (IV.a.)

Another issue that was brought up was the subsequent hydration of free lime in the ash truck. Improving the limestone utilization (to reduce the amount of free lime) reduced the problems at one plant. The addition of sugar also slows down the reaction. One plant is seeking to try this approach. Another plant uses cement mixers rather than conventional trucks.

V. Equipment and Service Supplier's Panel Report - Lou Gonzalez, B&A Inc., Engineers – Panel Leader

The panel members were Gary Goetz (Alstom Power, Inc.), Sean Li (Foster Wheeler), Chuck Beitel (Burns & McDonnell), and Kelly Bonds (Aegis Environmental). The supplier side continued to promote the need for good project definition and early/continuous dialogue amongst the project participants. In the early stages it is important to identify the goals of the project, the available fuels that are intended to be used, the emissions limits, the budget requirements, and the type of operations (base load, load following, cycling, fuel variation, etc.). Identification of the potential fuels for the plant is key.

While CFBs can burn a wide range of fuels, the units still need to be designed to accommodate the range of fuel properties. Different fuels impact the boiler in different ways. High sulfur fuels require considerably more limestone for sulfur control. High ash content fuels require more ash handling capacity and typically require more fuel feed handling (since high ash content usually reduces the heating value of the fuel). Particle size distribution is critical to the management of the fluid bed itself. Understanding how the various fuels impact the particle size is key to good operation.

During the early stages of a project it is important to identify the high risk items including materials handling, back end equipment, limestone issues, and ash handling equipment. A "fuel matrix" is helpful in organizing the fuel choices and impacts on the plant. The process is iterative. The impacts of fuel, permits, costs, size, and O&M all require some trade offs before the final choices can be made. It is preferable to get these finalized before the boiler design is carried out.

There is a lot of pressure on cost and environmental performance. The goal is to get to a permit that allows the plant to reasonably operate. The ash issues include cooling, erosion, capacity, and disposal. Smaller plants tend to generate less ash, making the overall handling problem somewhat less problematical. Larger plants with waste fuels generate tremendous quantities of ash, which poses more challenging problems in terms of cooling, handling, disposal, and capacity.

Permit requirements are driving the fluid beds toward additional back end scrubbing equipment for SO2 and possibly NOx control. The process for getting a permit is time consuming. The plant needs a permit that allows for realistic operation of the unit and flexibility to meet process needs. Timely filing of permit applications is very important to the overall success of the project. Schedule considerations include the fact the overall schedules are getting longer due to material supply issues and construction issues (both equipment and labor). Starting early with the planning process is key to getting the project scheduled effectively.

Commercial considerations point to the fact that risk carries costs. Careful review of the various high risk elements of the project can serve to reduce overall risk (i.e. dropping a fuel choice due to operational risk). Strategic alliances including partnering and "open book" arrangements can help to share the risks and rewards.

VI. Overview of Environmental Rules and Regulations Affecting New and Existing Fluidized Bed Boilers – J. Russell Bailey III, Trinity Consultants, Inc.

The 1970 Clear Air Act Amendments provided the National Ambient Air Quality Standards, the New Source Performance Standards, the National Emissions Standards for Hazardous Air Pollutants, and the State Implementation Plans. The 1977 Amendments provided revisions to the NSPS. The 1990 Clean Air Act Amendments led to an explosion of regulation including market based programs for acid rain. There are several types of emissions limitations including fixed emissions limits, market based programs, and case by case limitations. There are overlaps in these programs. The fixed limits (command and control) include SIPs, NSPS, NESHAP (including MACT), NOx Acid Rain, and RACT. Rules are moving toward market based programs which provide overall reduction levels and allow tradeable permits to emit certain pollutants.

The Acid Rain program for SO2 was the first market based program and was very successful. There are regional programs for NOx and proposed programs for mercury. There have been some proposals for CO2 as well, which is not currently regulated. Fluid bed units are subject to NSPS, MACT, Acid Rain (SO2, NOx SIP, and CAIR), and various case by case situations. The NSPS are based upon Best Demonstrated Technology. For boilers, Section Da is for utilities, Db and Dc is for industrial/commercial/institutional, and D (pre 1984 for ICI and pre 1978 for utility). The break point for Db and Dc is 100 MMBTU/hr. A utility unit is one that is larger than 250 MMBTU/hr that sells more than 33% of its output to the grid. For utility units, particulates, SO2, NOx, and mercury are now critieria pollutants.

The Db designation is for NOx, SO2, and particulates. The most recent update for NSPS was effective Feb. 28, 2005. For new utility units, output based standards are now required (lb/Mwhr). For reconstructed or modified units, there is a choice of lb/MMBTU or per cent removal. For ICI units, the NOx limit is an output standard. The SO2 limit provides some flexibility in the choice of standard. The mercury limits for utility units are all output based and vary by fuel. The Industrial Boiler MACT rule applies to all major sources of HAP (those plants with potential to emit 10 T/yr of any one HAP or 25 T/yr of all HAP). Particulate matter has been designated as the surrogate for metal HAP. The organic surrogate is CO and the halide surrogate is chloride. Mercury is the surrogate for heavy metals.

In the eastern US there is a transition underway to market based programs for most of the criteria pollutants. The first program was the national Acid Rain program for SO2. The NOx SIP Call provided state-by-state NOx budgets to be achieved according to state allocations for each segment. The CAIR rule will overlay the SIP Call. States are left to determine how to deal with sources that are covered by the SIP Call but are not covered by CAIR. The NAAQS and visibility will continue to drive new regulatory programs. The new PM2.5 NAAQS are due to be finalized in 2006. More areas will become non-attainment. The BART rules come from visibility requirements. States must show Reasonable Further Progress (RFP) toward meeting the drive to background level visibility by 2064.

VII. Overview of FERC Activities - Lauren W. Laabs, CH2M Hill

The FERC has purvey over PURPA, Combined Heat & Power, Distributed Generation, and PUCHA activities. The Energy Policy Act of 2005 contained PURPA "reforms", PUCHA "repeal", incentives for domestic fuel sources, and incentives for efficiency. The original PURPA Act of 1978 was intended to encourage the development of more efficiency use of energy. Qualified Facilities (QFs) were granted the right to mandatory purchase and sale agreements for power along with the right to be connected to the grid. A QF was not treated as a utility for purposes of overall utility regulations (i.e. holding company, rate regulations, etc.). The 2005 act revises the definitions of QF and user in order to eliminate "sham" QFs. FERC attempted to over simplify to new rules in the application of the act. CIBO provided substantial comments to the proposed rule. These comments were largely adopted. However, there is still a requirement to file a rate case to FERC under Section 205. This filing provides the FERC with the potential opportunity to "back door" regulate the plant in the future. A pending NOPR impacts the mandatory purchase and sale of electricity from a QF. The FERC made the assumption that if there is a regional transportation organization (RTO), an open market exists. If an open market exists, the mandatory rules are voided. This is not necessarily the case. Comments back to FERC have recommended a case by case approach. The burden has now shifted to the cogenerator. The EPA has indicated that cogeneration has beneficial environmental effects. They have filed comments that parallel the QF community.

The EPA Act of 2005 directed that a reliability organization be empowered to provide reliability standard for the industry. The NERC has petitioned the FERC to be that organization. There are a number of issues to be considered including size threshold, direct protection, priority (NERC vs. RTO), security and oversight, etc.

The CAIR rule preamble tried to align the definitions of cogenerators with the 25 MW cutoff and the efficiency standards. The FERC then proposed some changes. As a result, the EPA has filed more comments covering this topic.

VIII. Permitting FBC in Today's Environment - Bob Fraser, ENSR International

The goal is to try to design and permit the plant for the least cost fuels that are available over the life of the plant. Traditional fossil fuels are relatively uniform compared to opportunity fuels. Proximity fuels include low quality lignite, anthracite tailings (culm), bituminous tailings (gob), and delayed petroleum coke. These fuels generally are not economical to ship any significant distances. Plant location near these fuels could make economic sense. One caution is the relative amount of fuel. A waste coal pile can generally support only one or two units for any serious length of time. Having 5 or 6 projects all vying for the same pile cannot be supported. Biomass is also an opportunity fuel that cannot support much shipment as they are high in moisture. Although the ash content is generally low, the potential contaminants are important and are dependent upon the local conditions. Other fuel considerations include tire derived fuels, ash with high carbon loss (LOI), auto fluff, construction waste, and others. Further consideration needs to be given to blending and mixing of these fuels. Although these fuels can be burned, it is not always economical to do so when all of the potential impacts are considered.

Replacement, Repowering, and Retrofitting can get into "Netting". The goal is to avoid NSR by "netting out" of PSD review. Available reductions in actual emissions can be used to net out and thus avoid PSD BACT, Class 1 Modeling, and other permit requirements. Plant wide applicability limits should be utilized where possible so that overall emissions can be considered rather than individual unit emissions.

BACT requires Best Available Control Technology. New utility units must satisfy "top down" BACT. AES Puerto Rico was the first to use an add on SO2 scrubber due to being in a non-attainment area for particulate. The permit limit is at 0.022 lb/MMBTU for SO2. The required control level is 98.9% removal. Several other units are now being permitted at these levels. In particular, one wood-fired plant is at 0.02. Regulators tend to look at these levels on a "fuel neutral" basis. We know that wood is a low sulfur fuel, but regulators don't necessarily appreciate this.

On NOx, the CFB levels have generally been at 0.07 lb/MMBTU. Recent PC units with SCR and low NOx burners have been permitted at 0.06 lb/MMBTU. Suppliers have been reluctant to guarantee 0.06 for CFBs. PM10 and PM2.5 have caused additional confusion.

The PM10 limits include filterable and condensable particulates according to EPA. Usually the particulate removal equipment is guaranteed on the basis of filterable PM. UltraBACT looks at sulfuric acid mist. Not much operating data is available for this measure. Guarantees are difficult to obtain and are generally based upon the sulfur level in the fuel. CO generally has not been a problem for CFBs.

There are other areas that come under BACT such as cooling towers, materials handling, fugitive dust, auxiliary boilers, and emergency generators. Mercury is subject to rules either as an EGU or an ICI boiler. While the majority of coals in the US are at about 9 lb/trillion BTU mercury, new units will need something like 60 - 70% mercury capture to meet new unit regulations. Trying to find one entity that can guarantee the mercury emission level is difficult. The mercury level in the coal is variable. The particulate removal device only works on the particulate mercury (as opposed to the vaporous mercury). The activated carbon supplier only supplies the material (like supplying limestone). There is currently little experience on an overall basis.

Those sites less than 300 km from a Class 1 area require a PSD treatment and approval of the federal land manager. Start-up and shut-down considerations must also be considered when applying for a permit. If not specifically covered in the permit, the unit must meet the permit limits over the entire load range including start-up, shut-down, and upset conditions.

Typical comments from permitting authorities include things such as "Project XYZ can make this limit; why can't your plant?" Or "there is no technological reason why this technology cannot be applied for this unit and this fuel". In one case, the agency wanted the plant to consider coal washing for a waste coal pile that was already washed.

Never the less, 3 -5 new CFB projects are permitted every year. CFBs are considered to be clean coal technology. Opportunities exist to net out. Many of these permit requirements are negotiable at the state level. The states need to be made aware of the variety of circumstances involved in the various plants.

IX. Case Study in US FBC Development - Bruce Miller, Penn State University

Penn State has been involved with the beef industry regarding the utilization of cow carcass as a supplemental fuel for coal fired boilers. This is a disposal problem for the industry in the US. In Europe, there have been a number of projects driven by the need to dispose of cattle due to mad cow disease (bovine spongiform encephalopathy - BSE). The university has coined the term "animal-tissue biomass" (ATB) to refer to carcasses and body parts. Animal parts that cannot be rendered into an animal feed can result in ATB. After BSE was detected in Canada and the US, a workshop was held in July, 2004. Besides routine disposal, there is USDA interest in eradication for disease control.

On an annual basis, there are about 4 billion lb/yr of ATB that require disposal. Disposal options include burial, incineration, rendering, alkylation, hydrolysis, and other processing. The Penn State project proposed to look at combustion of ATB for steam generation. The EPA indicated that CFBs are not permitted for this fuel at the present time, but there did not seem to be any technical reason that the fuel could not be utilized. Animal fats and greases have a better heating value than coal. Animal proteins are comparable to lower grade coals. ATB is similar to biomass and somewhat better than waste coals. ATB could be suitable for co-firing with coal.

The 123 existing CFB units in the US might provide potential opportunities for ATB disposal. McDonalds and Cargill sponsored a recent workshop on this subject. The boiler manufacturers, government agencies, plant owners, and the banks were all present. The boiler manufacturers informed the audience that the concept of co-firing ATB with coal was technically sound. The first step was to perform pilot scale testing.

In the first half of 2005, Penn State performed some testing on their 1 MMBTU/hr FBC. The first series of tests involve whole cow carcasses. There were also tests on specific high risk parts of the animal. There 35 tests firing coal with the various cow ATBs. Feeding the ATB into the bed at about 15% of the heat input indicate relatively little difference from firing coal alone. When the ATB was introduced above the bed, there were some CO spikes. Recent testing with the over-fire air indicated that this problem could be resolved. A larger scale demonstration is needed. Further testing is planned in May (over-fire air) and July (oxygen enhancements). Another workshop is planned. Consideration for whether several plants would be designated for this application or whether the concept of a "portable" unit to send to processing plants would be more economical

X. Ash Cooling in Fluid Bed Boilers, Can Ash Coolers Take The Heat - Charles Wagner, Burns & Roe Enterprises, Inc., and Tom Alberts, Consultant

CFB bottom ash design issues include system design criteria, efficiency enhancements, ash cooling system problems, and conveying systems. The efficiency question comes about as a result of the ash level in the fuel. Very high ash fuels generally cannot afford to throw away the heat in the ash. The ash cooling systems need to consider wear, binding, blow through, and agglomeration. Conveying systems include pressure pneumatic, vacuum pneumatic, and mechanical systems. Any of these systems must be tolerant of wear and erosion. The highest quality materials need to be selected. Redundancy needs to be considered for critical parts such as screw coolers and drain systems. Typically systems should be designed so that 75% of the equipment can carry full load.

Screw coolers utilize the Holo-Flite or similar construction that allows the flights of the screw to be cooled while moving the high temperature solids. High weld quality is a critical factor in the survival of this equipment in high temperature service. The trough which houses the screw contributes to the overall cooling. Wear tends to be concentrated on the first 3 feet of the screws beneath the bed drain inlet. Wear on the face flight is most often seen. Wear on the rear flight is indicative of highly fluidic ash filling the inlet section up to the bottoms of the covers. This can be alleviated with a downcomer inlet extension. The trough does not usually experience wear bottoms. In those cases that experience such wear, hard facing or wear bars can be utilized. Erosion protection features include a transition plate (solid flight), wear ribbons, rifle bars inside the trough, replaceable shaft sleeves, relocated inlet with extensions, spherical bearings, and hard weld overlay.

A field survey of about 40 plants showed that eastern plants with waste fuels had more wear than western plants. One key factor is the tip speed of the screw compared to the required heat transfer. Since wear is proportional to the cube of the velocity, doubling the velocity increases wear by a factor of 8. A margin of safety is used for tip speed selection. One new development with a “double helix” screw arrangement allows the unit to run at half speed, which greatly reduces wear.

XI. Rotating Ash Coolers for Bottom Ash Cooling in CFBs - Guanglong Guo and Shifu Kang, Songling Power Environmental Equipment, Ltd. (China) and Sean Li, Foster Wheeler

Sonling makes rotating ash coolers in China, which have become the standard for FBC units in China. Mr. Guo bought out a state owned company in 1999 in Qingdao province (makers of the beer). The company has about 300 employees and about $12 million in annual revenue. They have sold over 200 ash coolers since 2001 with 150 coolers in operation. Over half of these coolers are over 20 t/hr capacity. These coolers have been retrofit on boilers made by Harbin, Shanghai, and Dongfong boiler works. For boilers over 100 MW, over 30 coolers have been retrofit for units with ash content over 28% (up to 54%). A total of 85 coolers have been sold on new units over 100 MW including other additional boiler manufacturers.

The rotating ash cooler is like a cement kiln with a reverse flow. The water flow comes in from the ash outlet end and moves through an inner jacket and then back through an outer jacket. The solids flow into the unit is by gravity. The ash feed is controlled by the rotation speed. A variable frequency drive controls the rotation speed based on the bed conditions. The ash flow of the kiln is also basically by gravity. As a result, wear is minimal. The auxiliary power requirement is about 18 Kw for the 20 t/hr cooler. There are fins (about 4 inches) inside the barrel that basically assist the flow of solids as the barrel rotates. They also assist in heat transfer to the cooling water. The solids are cooled to below 100 C.

The rotation speed is typically 4 - 6 rpm. The barrel length is about 10 meters. The barrel support design is an adjustable roller support system. The water inlet station provides a triple level of safety wherein the unit will not start up without water flow to the unit. The diameter ranges from about 6 ft to 9 ft for the 10 and 20 t/hr coolers. The cooler is vented to the back pass so that a negative pressure is maintained in the cooler.

In one plant in Jining, China, the fluid bed ash coolers were experiencing serious plugging and agglomeration problems. Weekly shutdowns were being experienced. The boiler was supplied by Shanghai Boiler Works. The units were retrofit one year ago and have not experienced any shut downs due to the coolers during that time. Auxiliary power was reduced significantly. Another unit at Huaneng Power supplied by Harbin boiler works was experiencing severe plugging and agglomeration. The ash content of the fuel was continuously variable. The two FBACs were replaced with the rotating ash coolers to eliminate this problem. The Dagang Project was a 4 x 100 MW CFB from FW. Screw coolers were used, but had to be replaced every 6 months. These were replaced with locally fabricated screw coolers with no improvement. These will be replaced by the rotating ash coolers this year.

With the good experience with these coolers, the rotating ash cooler has become the standard ash cooler for large capacity, high ash fuels. Sonling now wants to sell these coolers in the US. Drag chain conveyors are typically used to take the ash from the cooler to the storage silos. Sonling also makes this equipment.

XII. Lessons Learned from Recent CFB Projects and Application to a New Project - Don Koza, Bechtel Power Corporation

Bechtel has built 19 CFB boilers at 12 plants with the major CFB boiler suppliers. At a pet coke plant in Louisiana, there were pet coke issues including the fact that the coke was delivered dripping wet. There were some limestone sizing properties. Once the sizing of the fuel and the limestone was optimized and controlled, deposits in the cyclone were essentially eliminated.

At a gob plant in Pennsylvania, air dried crushers were used to prepare the fuel. Fines from this process ended up burning in the upper regions of the furnace causing overheating problems. An anthracite waste plant in Pennsylvania utilized a blend of silt with the waste. However, the flowability test did not include the silt. There were problems with the water drainage as well as the bed drain coolers.

A lignite fired plant in Mississippi had a relatively high alkalinity in the ash. This material greatly reduced the amount of limestone required. However, the mine was not open at the time of design and testing. A Texas lignite was used for a variety of tests. However, the fuel had different clay and other properties. As a result, the plant experienced difficulties in handling and transporting the fuel as well as the ash.

Fuel properties are absolutely critical for proper design. A new project, Greene Energy, will utilize bituminous gob, slurry fines, and run of mine coal. Fuel will be delivered to the plant by barge. Stammler feeders will be used to reclaim the fuels. Each fuel will have specifically designed features to handle the characteristics of the fuel. Gob will be screened prior to crushing. Fines will be by passed in order to avoid additional fines production.

A fuel test matrix has been developed and includes crusher testing, flowability testing, and physical properties as well as the more traditional chemical analyses, ash analyses, and grindability. Fuels that are extremely cohesive require the ability to move fuel if it sits more than 24 hours. A variety of configurations and equipment modifications were needed to provide a system that could provide reliable fuel feed with no pluggage. The limestone system will feature an “on demand” pulverizer**.** The feed requirements necessitated the relocation of the limestone silos. These trade offs could not have been done without adequate characterization of the fuel and limestone. They would have been extremely costly to implement after the unit had been designed and built.

XIII. Improved Innovative Approaches to Sorbent Selection and Utilization - Jay Crilley, Mobotec USA Inc.

The Mobotec technology is based upon their ROFA system (rotating over fire air). This system provides asymmetrical air flows to aid in mixing and reaction time inside the boiler. The first fluid bed application was on bubbling bed in Europe where the SNCR was not making performance. The addition of the ROFA cut the NOx emission rate in half. For CFBs, the lateral mixing is less than desired. Channeling effects due to large plumes of combustion products can result from the solids feed system. For the Colver project, the over fire air would be relocated to a point above the dense part of the bed, but below the first omega tubes. The CO level was reduced to below 20 ppm. The oxygen concentrations were leveled out. The additional turbulence provides better mixing of the limestone, which improves limestone utilization. The gas temperatures are more uniform as well. The upper furnace mixing can improve limestone utilization by 10 - 20%. The CO is reduced. The NOx is often reduced. With the more uniform velocity, the erosion potential is reduced.

At the Colver unit, the system was started up on May 4, 2006. The fuel and additive rates were held constant and the ROFA system turned on. The SO2 emissions dropped by 50%. The ammonia usage dropped for the same NOx level. Alternatively, a lower NOx level can be achieved at the same ammonia flow. The superheater spray flows have been reduced. With the potential reductions in limestone usage, CO, etc., there will be overall efficiency gains as well.

The rotating over fire air system consists of a nozzle within a nozzle to provide a jet to break up the planar flow in the CFB. These nozzles can be adjusted to achieve the mixing desired. A boost fan provides the high velocity, high pressure air. The boost fan at Colver is a 700 hp fan and is probably over sized. Pressure part modifications are required for retrofit on existing units. Mobotec supplies the tube bends that are needed to install the system. Two swirls are generated in the furnace, starting in opposite corners.

XIV. Heat Exchanger Retrofit and Upgrade for Improved Performance
Philip Jones, Scrubgrass Generating Facility
Ian Pullan, Boiler Tube Company

Ian Pullan reported on an economizer replacement at the Scrubgrass plant. This Tampella CFB was started up in 1993 and suffered ash erosion tube leaks in the economizer at the tube supports and return bends. Tube leaks were occurring every 3 months. The plant eventually bypassed the lower bank of the economizer, sacrificing efficiency for operation. BTA proposed a "H" fin design for the economizer replacement. The "H" fin selection allows for wide fin spacing and aligns the fin in the direction of the flow to reduce deposits. Solids that do drop out "fall through" the bundle. The tube size was reduced from 2 inches to 1.5 inches. This allowed for more tubes to be utilized. Although there was more heat transfer surface than the bare tube economizer, the weight was the same, but the pressure drop was reduced. After 3 years of operation the economizer looks relatively clean. The soot blowers are used every 6 months whether the unit needs it or not. The "H" fin design has been used on a wide variety of fuels and boilers. They are still looking for a reference on PRB coal.

Phil Jones reported that the Scrubgrass plant is a nominal 83 MW net plant with 2 units of 400 kpph boilers. Each unit has one combustor, 2 cyclones, and one backpass. There is also one ID and one FD fan. The first economizer failure caused a significant tube leak which got water into the ash system. This caused the ash silo to fill up. The next type of failures was from the economizer edges. Insulation and baffles were installed. This allowed operation for some time, but drove the wear toward the middle of the economizer. Some of these leaks caused problems with the air pre-heater as ash built up in the entrance to the air pre-heater. The original economizer has a 125 mil wall compared to a minimum wall requirement of 117 mils. This leaves only an 8 mil tolerance for wear. The new economizer has a 200 mil wall with a minimum wall requirement of 70 mils. This gives a much larger tolerance for wear. The inline design of the new economizer, along with the smaller tubes essentially eliminates the build up of ash in the economizer.

XV. Update on Industrial Scale PFBC Boilers - Don Bonk, DOE

The Cedar Lane Farms project at a greenhouse in Ohio is a small CFB (8 MMBTU/hr) that operates during the heating season. Although the unit is small, it still had to meet sulfur capture requirements. As the unit is small and is a hot water heater, an operator is not required. The unit ran last year for 193 days with 97% availability with computer controlled operation. This year, there was a 200 day heating season with 99.9% availability. This CFB has 100% turn down as the unit can be slumped for at least 6 hours and restarted automatically. This system has saved over $200 K/yr compared to natural gas. The Farms is planning to expand the coverage with additional CFBs. A final report has been submitted to DOE for approval.

The former ABB PFBC technology has been purchased by a small company in Pennsylvania (EET). The former test facility from Finspong, Sweden will be installed at the Consol Coal test facility in Library, PA. Coal from the Vartan plant will be used to calibrate the operation. Waste coal slurry is planned to be the primary fuel for commercial plants. The PFBC-EET 240 MW design is essentially a 2 x P200 system. In arid regions, PFBC could be used as a coal fired gas turbine to minimize water use and improve overall performance by using an HRSG to improve the overall system performance. The State of Illinois is doing a joint project with DOE to develop a 20 MW system for this type application.

Industrial gasification is more accepted on a world wide basis rather than the US. Most of the coal gasification units in the world make synthesis gas for chemicals such as ammonia production or acetic anhydride. Bulk chemicals are especially sensitive to natural gas costs. The business challenges for increased utilization of coal gasification for industrial applications include natural gas price volatility, project cost uncertainty, project timing, and capital limitations. Technological challenges include efficiency/reliability, scalability issues, and process integration concerns. Currently there are some large scale industrial gasification systems making up 40% of the industrial market.

The industrial park concept has not been successful. Existing industrial clusters, where several potential gas users are within a mile of each other, provides an opportunity for a regional gas producer plant. Small industry owned plants face the loss of economies of scale and possible reliability issues (i.e. single train systems). The DOE goal is to eventually replace 35% of the natural gas used by the industrial sector. This figure is aimed at the market segment that needs process gas. For heat and electricity only, combustion processes are cheaper. The relative cost for small systems indicated that a small CFB would be about $40 MM and a similar gasification system would be $67 million.

XV. National Academy's RCRA Ash Final Report – Discussion Panel
Gary Merritt, Moderator, Inter-Power/AhlCon Partners, L.P.
Dave Eslinger, Primary Energy Holdings, LLC

The first panel consisted of Robin Ridgway (Purdue University), Deborah Dale (US DOI Office of Surface Mining), and Truett DeGeare (US EPA Office of Solid Waste), Robin was one of the 15 members of the NAS team that was selected to evaluate management practices for coal combustion residues (ash). There are over 120 million tons of coal combustion residues in the US each year. Congress mandated the study to examine the health, safety, and environmental risks from the use of CCRs for placement in coal mines. The statement of task was very specific and included the adequacy of data collection, impacts on aquatic life, responses of mine operators to adverse impacts, adequate characterization, and clear performance standards for beneficial use in mines. In addition, isolation requirements, adequate monitoring, economically productive post mine land use, upgraded bonding, and public involvement.

The study process had an 18 month schedule including 7 meetings (6 information gathering) including public sessions and site visits. Testimony and presentations were taken from 120 people. The report is a consensus report that is peer reviewed. The overall conclusion is that putting CCRs in coals mines as part of a reclamation process is a viable management option. The placement must be properly planned and monitored.

At the present time, there is comparatively little data that is know about the potential for mine filling to degrade ground water or surface water. There are no known such cases reported to EPA. Secondary uses of CCRs should be strongly encouraged. Routine analyses of CCRs are needed to potentially identify toxic materials and to ensure that proper practice is used to minimize any impact. Comprehensive site characterization specific to the mine in question along with the detailed characterization of material to be placed is imperative.

Integration of CCR and site characterization needs to be carried out. Minimizing the interaction with water is a key feature as water tends to mobilize and transport undesirable elements. Current monitoring programs are insufficient. Mines reclaimed with large amounts of CCRs can achieve economically productive post mine land use. Deeds should record and disclose where materials have been placed. This is primarily an issue for well water (such wells should be avoided). The committee recommends additional research on leaching tests, monitoring, and characterization techniques. The committee concluded that the scope of SMCRA is sufficiently broad to cover regulation of CCRs at mine sites. EPA has proposed to provide specific regulations for mine placement. Disposal of CCRs should be subject to reasonable standards. Current guidance is inadequate.

Truett DeGeare noted that OSW has been studying the risk of coal ash to the environment for a very long time. In October 1980 the Bevill Amendment temporarily exempted coal ash from hazardous waste regulation. This was restated in 1988 and again in 1998. In 2000, EPA published its final determination that coal ash was not a hazardous waste and would be regulated under subpart D regulations. In November 2003, Congress directed EPA to contract the NAS to study risks associated with the use of CCRs in mines. In September 2004, the NAS established the committee to carry out the task. The report was issued on March 1, 2006. The basic conclusion is that placement of CCRs in mines is a viable option provided that it is part of an overall reclamation plan and that adequate public involvement is provided with appropriate permits, etc. EPA endorses the increased utilization of CCRs and supports a goal of increased beneficial use from 31% to 50% by 2011.

Debbie Dale reported that the Department of Interior Office of Surface Mining is still reviewing the report and is not ready to take a public position. The report recommends thorough characterization of the site and the CCRs. There are states that have good practices. Standardization of these practices across the country is a desirable goal. Likewise, a comprehensive monitoring program was also recommended. Again, several states have good monitoring programs. Standardization of these practices across the country would bring more certainty on the impact of placements.

The Surface Mining Control and Reclamation Act (SMCRA) provides for permits for mines. Ash disposal in a mine should constitute a “significant alteration” of the reclamation plan. This would provide for a public comment period ahead of permit approval for mine placement.

Minimizing the interaction with water likely means placement above the water table. It is difficult to apply a liner to an active mine. SMCRA is currently vague on mine placement, but does appear to have scope for regulation. Federal standards are needed, but with flexibility for states to adapt to the variation of conditions in the various states. While mining falls under DOI, solid waste falls under EPA. There is a need to clarify the regulatory authority for this particular application. The placement back in existing mines reduces the need for additional sites for ash disposal. No contamination as a result of CCR placement has been proven at any SMCRA mine site. EPA evaluated 24 sites in 1999. As the experience with mine placements builds, more long term data needs to be collected and analyzed. Model validation (comparing predicted movements with actual movements) is needed.

Roger Hornberger of the Pennsylvania DEP reported on PA’s reaction to the NAS report. Pennsylvania, in concert with Penn State University, have written a 400 page report on coal ash. This was used as input for PA’s testimony to the NAS report. PA is reviewing the report to see what rules, if any, would need to be modified in PA. PA agrees with the conclusion that CCR mine placement is a viable option is done right.

Further the SMCRA regulatory scope is aligned with the PA program. On the testing and monitoring conclusions, PA is basically in agreement. They also agree that more R&D is needed. One issue with the damage case statement is that there seems to be an implication that if only one could look harder at these 24 EPA sites, some damage might be found. The other issue is with a factual error on the NEPCO site regarding the amount of money spent at that site. The state would like to get that information corrected. There are 16 FBC sites within PA. There are 21 conventional PC sites in PA. Although the PC units burn more tons of coal, the CFB units burn waste coals and, thus, that ash production from the 2 sets of sites are about the same at 5 million tons each annually. A large portion of this ash is utilized beneficially in mines. If ash is brought in at the optimum moisture content, compaction will be successful.

The Westwood plant was built over 20 years ago. The coal refuse pile dominated the site. This pile has been completely consumed and reclaimed. Plants at Schullkyl, NEPCO, and Gilberton have all demonstrated major reclamation of damaged sites due to waste coal piles. Groundwater monitoring wells have demonstrated improvements in water quality (less acidity). Acidity, sulfate, and iron have all been decreased in surface water and groundwater at these plants. Several open pits have been reclaimed and re-vegetated.

PA has 3 “one of a kind” sites. These are either wet sites or actual pools or ponds of deep water that is contaminated. At the NEPCO site, the use of CFB ash brought the water pH from 4 up to 11. A stable ash plain was established. Elements of Portland cement were established in the placement. The combination of materials in the water and materials in the ash worked together synergistically to remediate the site.

XVII. Fundamentals of Ash and Mine Characterization – Paul Ziemkiewicz, PhD., WV Water Research Institute

Several applications are utilized for ash utilization including underground grouting, refuse replacement, back filling, and drainage neutralization. The state has a lot of experience with grouting. The goal is to reduce the flow of acid mine drainage. At one mine the flow was reduced from over 300 gpm to about 8 gpm. This is a key improvement (not covered in the NAS report). Although the water quality was little changed before and after grouting, the total flow was substantially reduced, thus reducing the total amount of heavy metals, etc. that are emanating from the drainage. Generally speaking, iron and aluminum are improved dramatically. Arsenic and silver were generally under detection limits. Even in cases were metals were detected (lead and selenium), levels were well below drinking water standards.

A test procedure was developed to simulate the action of ash placement and acid mine drainage. The action moves through several phases as the water exchanges ions with the solid materials. Two types of acid mine drainage (strong and mild) were used in the tests. The field results showed better agreement with the strong acid mine drainage than the mild. This points to the difficulty of coming up with one test that can characterize all types of sites and ash.

A risk table was created relating risk factors (ground water velocity, saturation, CCR hydrological conductivity, ground water pH, and CCR buffering potential) to high, medium, and low risk values. Assigning risk levels of 5, 3, and 1 for high, medium, and low, one can sum up the overall risk level and make a determination as to the overall level of risk. One of the caveats, that was brought out, was that monitoring data, etc. that is submitted to a state agency for permit purposes is public data. Any citizen, or citizens group, or law firm can scrutinize the data. This data can end up in court. It is important to review data that is submitted to be sure that it is accurate and representative.

XIII. Plant Tour Overview - Ed Missal, Suez-NEPCO Cogeneration Facility

The NEPCO facility is about 70 miles away. The plant came on line in September 1989. It has a 20 year power purchase agreement with Pennsylvania Power and Light. The steam customer is a major greenhouse. The boiler is a CE CFB using Lurgi technology. The steam turbine is an ABB VAX turbine. The tour will start at the ash reclaim pit (named the big Gorilla pit). Ash placement started in 1998. By 2000, about 1/3 of the pit was filled with a very stable ash platform. In 2003, the water portion was filled in. The remaining fill is to bring the site back to its original contour. The first reclamation areas are already vegetated. After the reclaim area, the actual plant will be toured.