

## CIBO Industrial Emissions Control Technology IV

July 31 - Aug. 3, 2006

Toledo, Ohio

### I. Mini Workshop - Clean Air Fundamentals and Compliance 201 - Moderator: Fred Fendt, Rohm and Haas Company

Ronald Lutwen, Orbital Technology Solutions, reported on “The Health Reasons for the Clean Air Act and Need for Action”. Ron noted that we all want a clean environment. The key is to control the low levels of emitted pollutants at reasonable cost. SO<sub>2</sub> is considered to be a prime cause of acid rain. When inhaled, the SO<sub>2</sub> converts into sulfate particles which can be damaging to the lungs, particularly in people that are sensitive to respiratory problems such as asthmatics. SO<sub>2</sub> can be controlled by switching to a lower sulfur fuel or by deploying SO<sub>2</sub> scrubbers. Particulate matter has been determined as a key pollutant that gets into the lungs and irritates the linings and fine passages. Particulates also carry a number of trace elements that can be harmful. Particulates can be controlled by switching to a lower ash fuel or by installing electrostatic precipitators or bag houses. CO binds with the hemoglobin in the blood more rapidly than oxygen. In the extreme, enough CO can be bound to the blood to suffocate the lungs. CO is controlled by establishing good combustion conditions with adequate air flow. Ozone is formed when sunlight strikes the requisite particulates and hydrocarbons in the atmosphere (smog). Control is attained indirectly by controlling other pollutants such as NO<sub>x</sub>, hydrocarbons, and particulates. Mercury is a heavy metal that can cause brain damage. Although the emission levels are very low, mercury persists in the body and builds up over time. Mercury can be controlled by the addition of activated carbon. Other methods are being developed. NO<sub>x</sub> is a class of compounds that result from the oxidation nitrogen. NO<sub>x</sub> can be controlled by controlling the air flow to minimize the formation of NO<sub>x</sub> and by adding either catalytic (SCR) non-catalytic (SNCR) processes that reduce the NO<sub>x</sub> through reactions with ammonia. Hazardous Air Pollutants (HAPs) are identified as 189 metals and compounds that are considered by EPA to be hazardous to human health. The recent Boiler MACT rules have been issued to control HAPs. These HAPs have been aggregated to simplify the controls. Particulates include particulate HAPs. CO covers hydrocarbons (HC) and volatile organic compounds (VOC). Mercury includes heavy metals. Chlorides include most of the gaseous inorganic HAPs.

Maxine Dewbury, The Proctor & Gamble Company, reported on “An Overview of the Act and A Simple Discussion of the Industrial Issues”. Ambient standards include primary standards and secondary standards are updated every 5 years based on the latest science. The country is divided into attainment and non-attainment areas. The non-attainment areas are those that do not meet the ambient air quality standards. Over the last 30 years, the vast majority of the country has come into attainment for the primary standards. Ozone has been more of a problem and has the most non-attainment areas.

Emissions have been reduced more than 50% in spite of an increase in GDP by nearly 200% (as well as increased population, increased vehicle miles, and increased production). These reductions have been accomplished by the control requirements of the Clean Air Act. Stationary sources have New Source Performance Standards, major and minor New Source Review, State Best Available Control Technology (BACT) rules, and State Implementation Plans (SIPs). Under a SIP, EPA delegates to each state the responsibility to do the planning and implementation of controls to come under attainment. In 1990, the Clean Air Act was amended to change the structure of the non-attainment areas to include more classifications on non-attainment for ozone with time periods and control requirements for each classification. Hydrocarbon and NOx precursor controls were required. Reasonably Achievable Control Technology (RACT) was prescribed for existing units. The 1990 amendments also set up criteria for the 189 HAPs with the requirement for Maximum Achievable Control Technology (MACT) for these compounds. EPA had to set up rules for all of these HAPs and processes that emit them over a 10 year period. The amendments also set up an operating permit requirement under Title V. For major sources, a Title V permit is required which covers all emissions at the plant. The permit is updated annually. The amendments also provided tougher penalties for violations including civil and criminal penalties. The NSPS apply to new or modified/reconstructed units. The trigger for modified or reconstructed units is an hourly increase in emissions or a cost of more than 50% of a new unit. This trigger has been debated and has been a source of much litigation since the Clinton Administration. RACT and Best Available Retrofit Technology (BART) applies to existing units. The NESHAP and MACT standards also apply to existing units with regard to HAPs. There are construction permit requirements at the state level that must be obtained before construction can begin under the SIP. Once the plant is in operation, there is the Title V permit and a state permit to be obtained.

Maxine Dewbury also reported on current issues in front of CIBO. These include NAAQS, NSR, Boiler MACT, and BART/Regional haze. The National Ambient Air Quality Standards have been recently tightened for ozone and fine particulates. This has put more areas into non-attainment. This in turn places more requirements on areas that are in non-attainment, including RACT, BART, BACT, and Lowest Achievable Emission Rate (LAER). States are in the process of modifying their SIPs for ozone by June 2007 and for particulates by February 2008. Under the Regional Haze Rules, visibility is addressed. This requires the nation to achieve the natural level of background visibility by 2064. Every 10 years, sources are tested to determine if they are on the path to achieving this goal. For the HAPs, the MACT rules have been issued. In particular, the Industrial Boiler MACT has been issued, which include rules for metals (as particulates), CO, chlorides, and mercury. The environmentalists have sued EPA over this rule and CIBO is supporting EPA in this litigation. New Source Review has been a major problem since the Clinton Administration decided to re-interpret the meaning of what constitutes a modification. EPA has since proposed some reforms. The emissions increase rule has been upheld. However, the provisions for "clean unit" identification were struck down. The equipment replacement rule was also struck down in its entirety. EPA is working on revisions. Some utility companies have contested the NSR accusations and have had some success. In particular, Ohio Edison and Duke Energy

were successful, although the Duke case is now going to the Supreme Court. Alabama Power has a similar case to Duke. TVA also had some success. Title V requires a lot of cost for an operating permit. Costs include an initial fee of \$50 K, annual costs of \$22 K, additional monitoring requirements, and additional reporting requirements. Monitoring rule making and guidance was brought to litigation in which EPA lost. However, EPA ignored the court decision and continued to push for additional monitoring. We have been pushing EPA to correct their guidance in this area. Under the Resource Conservation and Reclamation Act (RCRA), fossil fuel ash was determined to be a “special waste” rather than a hazardous waste. There have been a number of attempts to circumvent this determination. A study was called for by Congress at the National Academy of Sciences (NAS). The report was issued and did not recommend that fly ash be regulated as a hazardous waste.

Jason Swofford, Trinity Consultants, Inc., gave “An Overview of the Compliance Requirements. Once a plant has determined which rules apply, a compliance program is needed. There are federal laws, state laws, and local laws, all of which can impact the operation of a plant. EPA has a number of web sites which can provide some help in finding out about the applicability of rules and regulations to a particular plant. A compliance program includes task identification, training, compliance demonstration, and auditing. For each rule or regulation that has a compliance requirement, there is a task or process that must be implemented to assure compliance. Compliance includes monitoring, record keeping, and reporting. Task identification is critical and requires paragraph by paragraph review of the requirements of the rule. Tasks need to be identified in plain language so that staff can understand exactly what is needed in order to meet the requirements. Responsibilities need to be assigned and tasks organized and scheduled to meet the compliance requirements. Staff training is critical to implementation. Clear communication of the impact of the regulation and the responsibility for compliance is necessary to make the employee a part of the compliance team. Once the controls are in place and the plant is running, monitoring is usually required. The regulations usually specify what to monitor, how often to monitor, what method to use for monitoring, how to calibrate, and what accuracy is needed. Record keeping is required and the frequency and retention period is specified. The major decision is whether or not to automate the record keeping system. Reporting is driven by regulations including what to report, when to report, and what to certify, as well as retention. Care should be taken to understand which agencies must get a copy of the report. Staggering may be a useful option to avoid massive reporting requirements on Dec. 31<sup>st</sup>. Auditing can be informal as well as formal. Internal audits can be scheduled. EPA audits can occur at any time. A good internal audit plan should show implementation and documentation of corrective action. Internal audits should be “harsher” than EPA audits to minimize problems when an impromptu audit occurs. Management support is crucial to accomplishing all of these tasks due to the amount of cooperation and coordination that is needed throughout the organization.

Vince Albanese, Fuel Tech, Inc., reported on “A Discussion of Compliance Pitfalls”. With the experience of implementing 400 projects to meet environmental regulations, this report hopes to provide straight talk about compliance. The critical first step is

understanding the emissions inventory of the plant. Hesitation results in cost. There is currently a tremendous demand for resources on the supply side due to regulations on the utility sector. Over 100,000 MW will be retrofitted through 2010 in response to regulations. Additional coal-fired plants are now being built to support the grid. In acid rain and ozone requirements, a number of plants were required to install low NOx burner technology. There was another group that was exempt. However, other regulations started to make NOx requirements. As a result, the exempt group ended up with more NOx controls that were more stringent. Thus, being aware of overlapping control requirements is very important. "Managing up" is critical to assuring that adequate budget is available to manage the implementation plan to keep the plant in compliance. Managing the procurement process is also important. Schedule and quality are key items. In response to regulations, the utility industry is retrofitting 100,000 MW with pollution controls through 2010. In addition, new coal-fired plants are being added to support the grid. Thus, resources for pollution control equipment are becoming scarce. New suppliers may be coming into the business. Due diligence is an absolute necessity. IP indemnification and stiff guarantees are needed. Understanding the cost effectiveness of the solution is another necessity. The basic calculation is fairly simple. The amortized capital cost is added to the O&M cost and divided by the tons removed. However, there are any number of methods and assumptions involved in capital cost amortization. Don't forget balance of plant costs. For example, ammonia is used for NOx reductions. Handling ammonia involves security issues. These need to be accounted for. Don't forget fuel flexibility. Finally, beware of vagueness. Many initial estimates include a retrofit difficulty factor, a contingency factor, or a factored estimate factor. These are difficult to defend in front of a regulatory body. More detailed cost evaluations are needed.

## II. Mini Workshop - Coal Sampling and Analysis - 101 - Charles Renner, SGS Mineral Services

Coal is a very heterogeneous material. Thus, sample size, size characterization, size fractionation, etc. are all important factors in getting representative sample of the coal. ASTM has sampling standards for coal, which includes definitions for such terms as lot, increment, sample, gross sample, and representative sample. A key feature of sampling is that the result provides an estimate of the properties or composition of the larger amount of coal. Samples can then be divided, reduced, and prepared to a laboratory sample. The laboratory sample can then be further subdivided into an analysis sample for chemical analysis. Size characterization starts with top size and spacing increments. Time based sampling is recommended rather than mass based sampling.

Moisture in coal can be inherent or surface moisture. Coal is like a sponge with a pore structure. The surface moisture is normally determined by difference from the total moisture and the equilibrium moisture test. Finer particles typically have a higher moisture level than the coarse coal. Ash is also distributed differently throughout the coal. Sulfur is typically present in coal as pyritic sulfur or organic sulfur. There is also the possibility of sulfates in the ash. The calorific value (or heating value) is moisture and ash driven as these constituents dilute the fuel portion of the coal. The sulfur is often

characterized in terms of lb SO<sub>2</sub>/MMBTU. Sampling requires a plan. Plan your work so that you can work your plan. Experienced/trained personnel are valuable. ASTM has a number of sampling procedures for various types of situations. A sampling shovel should have sides such that the coarse material does not fall off. Sampling from a coal belt can be characterized into 4 types of samples: stopped belt cut, full stream cut, part stream cut, and stationary sampling. For trucks or rail cars, an auger sampler is used. The auger drills down into the compartment to collect the sample. A table is used to determine the size of the sample that is needed and the timing of the increments. With a representative sample for the laboratory, we still need to consider accuracy and precision. Precision means that the sample is taken precisely the same way, correctly, every time. Accuracy means that the method of analysis minimizes the degree of error. The proper use of accepted test methods helps to improve both the precision and accuracy. The objectives are to keep measurement errors small enough to meet the needs of those using the measurements, to eliminate bias, to make the measurements economically, and to assure that standards are followed. Repeatability concerns the ability of the analyzer to repeat the analysis with the same process and the same equipment within a short period of time. Reliability is the overall capability of the process. When coals are blended, some properties can be averaged and some cannot. The heating value can likely be averaged. The ash fusion temperature cannot. Grindability is not additive. Sample preparation is not additive. Contract language needs to be specific about the procedures for sampling, collection, handling, analyzing, etc. Written procedures should be specified along with audit rights. Variability needs to be understood. In order to improve the process, inspect the system, fix the obvious, set up the sampling plan, use control charts, monitor results, take corrective action, and be vigilant.

### III. Equipment Suppliers' Forum - Lauren Laabs, CH2M Hill

Bob Bessette pointed out that this session was for Associate members only. Bob gave the anti-trust admonition. Lauren noted that Boiler MACT compliance has been the significant topic. One question was whether customers are, indeed late, or behind in their plans to meet the MACT deadline. There have not been as many owners clamoring for controls as might have been expected. With regard to mercury control, many are looking at particulate controls with the potential to add activated carbon. One supplier pointed out that several plants were doing coal analysis and stack analysis and finding more mercury in the stack than in the coal. Others noted that they are trying to do full mercury balances as there are sometimes other sources of mercury (scrubber recycle water, pond water, etc.). Timing is getting to be an issue as utility demand is high at the moment. Many equipment suppliers are at capacity and not bidding on a number of jobs. Equipment prices have been increasing along with commodity prices. One of the presentations in the morning urged owners to ask for stiff guarantees with potential penalties up to the contract price. This approach does not appear to be realistic in view of the current demand. It was pointed out that there are potentially a lot of units that are not that well maintained that are not meeting their original performance ratings. Some customers are afraid of triggering NSR. In order to bring units into compliance, they need to be brought up to proper operating conditions. One question has been the acceptance of new technology. Many customers do not want serial number 1 and want 5

or 6 years to see serial number 2. One supplier noted that having a back up technology is helpful. Having a pilot operation somewhere is considerable. Working with a university that has an interest in developing technology can also be helpful. Another approach is to get state or federal funding to support the new technology introduction. Finding a state that is more receptive to new technology and would be willing to work with the customer and supplier in terms of compliance timing, etc. also provides some risk reduction in terms of meeting a compliance date. Financial incentive (i.e. price concession, schedule, etc.) is a requirement. Interest in coal has been increasing. Most of the potential customers are those that had coal fired unit, but switched to gas in the 80s and 90s. Now that the price of gas is high, coal is becoming more acceptable, even in smaller boilers. With regard to lime and limestone supply, customers want to get some kind of long term, stable pricing. Transportation costs are increasing with the cost of gasoline and diesel. Surcharges are substantial. Another question becomes whether or not fuel changes constitute a trigger for NSR.

#### IV. Fundamental Session - The Science of Particle Capture - Bob Taylor, GE Environmental

The need for particulate collection is either driven by regulation or the need for material recovery. Most particulate results from the inorganic constituent of the fuel. The remainder is usually unburned carbon. For a pulverized coal boiler about 15 - 20% of the ash falls out as bottom ash. For a stoker unit, 40 - 50% of the ash falls out as bottom ash. The dust burden is a function of the unit heat rate, the fuel heating value, and the fuel ash content. Dust loading is often reported in grains/cu-ft. There are 7,000 grains in a pound.

Cyclones are relatively simple devices often referred to as mechanical devices in the industry. Cyclones work by spinning the gas inside a cylinder. As the solids near the wall, due to centrifugal force, they are collected in the boundary layer. Cyclones need a relatively high velocity to be effective. In order to overcome this limitation, many small cyclones are put together in a multi-clone. Overall collection may be in the range of 80 - 90%. Wet scrubbers have been applied in industry for particulate control. Venturi scrubbers are very effective in removing particulate, but have very high pressure drop. Other types of scrubbers use internals, such as rods or packing, to provide collection points. These are subject to plugging. An electrostatic precipitator works by charging particles with a negative electrostatic charge. Charged particles are driven toward grounded collection plates. Very high collection efficiencies are possible. ESPs are typically effective over a wide range of particle sizes. There is a transition size around 0.5 - 1.5 microns where the ESP is less effective. The efficiency has an exponential relationship with the surface area of the electrodes and the gas volume. As more efficiency is required, the volume of the precipitator begins to climb exponentially. The particles migrate to the electrodes at some velocity perpendicular to the flow. This velocity is dependent upon the particle size, the strength of the electric field, and the gas viscosity. An ESP is a fractional collection device. This means that in each field, a fraction of the dust is removed. In the inlet field, the largest particles are removed. In the middle field, the efficiency is somewhat lower due to the lower average particle size. The outlet field collects the smallest particles on average. The advantages of an ESP are

that they have low pressure drop, durability, and flexibility. The disadvantages are that there is no barrier to dust flow. Any failure of fields or re-entrainment puts dust back into the gas flow. The ESP is also sensitive to carbon content. Size must increase in order to increase the collection efficiency of the device. A wet ESP operates at a lower temperature (and thus gas volume), but with a higher moisture content. These units have very high efficiency on fine dust. With the added moisture, the ash properties are not really a factor. The disadvantages are that corrosion resistant materials must be used, the waste products are wet, plume buoyancy is low, and the stack gas is visible. Fabric filters are becoming common, particularly with CFBs. Common types include reverse gas and pulse jet. Cloth (or some media) is used to collect dust by acting as a filter. In reverse gas technology, the gas flows upward through the bags so that the dust is collected on the inside of the bag. To recover the dust, the bag or compartment is isolated and then another gas (air) is flowed downward to push the particles into the hopper. The compartment is then re-exposed to gas flow. This is a barrier technology. The reverse gas filters usually have long bag life. They have a high removal efficiency. The disadvantages are that the filters are very large and proper maintenance is needed to attain long bag life. In pulse jet technology, the gas flows upward on the outside of the bag. The particles collect on the outside of the bag. The bag is sitting over a cage. A pulse of some other gas is used to dislodge particles on line. The advantages are that they are a barrier technology, some maintenance can be done on line, and the size is smaller. The disadvantages are a higher pressure drop, a variable pressure drop, sensitivity to gas temperature, sensitivity to gas moisture and sulfur, cleaning air quality is important, and bag life is a major cost impact. Hybrid collectors use the combination of an ESP and a bag filter. The ESP was used to collect the major amount of ash. The remaining ash went to a bag filter. This fine ash created a very dense layer on the bag filter which caused high pressure drops. As a result, the size of the filter portion had to be increased. All bag filters are subject to similar bag selection and design criteria. Temperature conditions are the first consideration. Higher temperature requires better quality bags. Abrasion and filter properties are next. Material sensitivities then determine the final selection. The air to cloth ratio is a criteria figure that represents the gas flow in actual cubic feet per minute divided by the area of the cloth. Reverse gas filters typically run at 2 ft/min. The pulse jet is at 4 ft/min.

#### V. Owners Forum and Equipment Suppliers Forum Report - Ann McIver, Harvey Beavers, Lauren Laabs.

Ann McIver reported on the Owners Forum. Boiler MACT was the major topic. Fuel sampling and analysis was a major concern. For equipment purchases, lead times are increasing. Stack testing for health based compliance must be done in a timely manner. Some states are insistent on meeting the required deadlines. Record keeping and operation limits are important. New Source Review was the next major topic. There is a lot of uncertainty on NSR right now. When thinking about NSR, a lawyer should be involved. Harvie Beavers pointed out that the industry is facing an aging work force. There is a scarcity of qualified operators. Training and education are needed.

Lauren Laabs reported on the Equipment Suppliers' Forum. Again Boiler MACT was a major topic. Resource limitations were reported by several members. Lead times are increasing. Labor and commodity costs are increasing. Getting new technology into the market place was discussed. Due to the regulatory penalties, it is getting more difficult to introduce new technology. NSR is another factor driving caution in the industry. Many owners are afraid to change a permitted unit so as not to trigger NSR.

## VI. Environmental Rules, Regulations, and Implementation in the Industrial Sector - Panel

The panel members included Jim Eddinger, EPA; Chris Rechhia, OTC; Ann McIver, Citizens Thermal Energy; and Praveen Amar, NESCAUM. Jim Eddinger reported on recent rules for industrial boilers. These include the Boiler MACT, the Industrial NSPS, and the area source rule making for Industrial Boilers. For MACT, the proposal date is January 13, 2003. This date defines whether or not a unit is considered to be a new unit. The promulgation date is Sept. 13, 2004. This sets the compliance date for existing units as Sept. 13, 2007. In order to qualify for health based standards, submittals are required by Sept. 13, 2006. There are some overlaps with the differences in definitions of the Title IV rules and Boiler MACT, which causes some IPP units to fall under both rules. EPA is coming up with an amendment to correct this. There are 9 categories of units under MACT. These are fuel and size based. There are several modes of compliance including fuel analysis, stack testing, and monitoring. There is although the health based certification which allows a unit to use a look up table to self certify for chlorides. The four pollutants are CO, particulates, mercury, and chlorides. Compliance issues include defining what is meant by "equivalent" in terms of analysis protocols. A consensus standard will be considered equivalent. Another issue is hybrid boilers. Definition by ABMA of a fire tube boiler will put such units in that category. Combustion of contraband material at the request of the government is not considered a fuel and not subject to MACT. Soot blowing is not necessarily part of the compliance testing. Read the guidance section for help in accounting for soot blowing. In order to average fuel inputs, good record keeping is required. A total of 5 petitions were received. Amendments were proposed for common stack testing and should be issued soon. The NRDC petition complained about lack of standards for all HAPs and the health based standard. EPA issued their position in December. They retained the health based standards and the surrogates as proposed. Revisions to the Industrial NSPS were proposed in Feb. 2005. SO<sub>2</sub> was set at 0.2 lb/MMBTU or 92% reduction. The particulate limit was set at 0.3 lb/MMBTU. The CIBO petition on this rule was granted by EPA. For Area rulemaking source categories include industrial and ICI boilers. A rule is required by 2008.

Chris Rechhia of the Ozone Transport Commission reported on the OTC attainment issues. In the Northeast, over half of the sources of ozone precursors come from highway vehicles. Another 20% comes from electric generation. Residential combustion also contributes. Industrial emissions contribute about 25%. The US standard is to meet and 80 ppb ozone standard with 8 hour averaging by 2010. The Northeast is generally in the 90 ppb range (moderate non attainment). A number of programs have deadlines to

submit plans to reach attainment in 2007. With the introduction of the CAIR rule, the expected non attainment area is the Interstate 95 corridor from Washington DC to Boston. Point sources include ICI boilers, cement kilns, lime kilns, glass furnaces, MSW, refineries, small diesel, and EGUs. For mobile sources, full penetration of reformulated gasoline, airports, and marine diesel are being looked at. For boilers, small units (< 25M MBTU/hr) would have a target of 10% NO<sub>x</sub> reduction. For 25 - 50 MMBTU, a range of reductions is proposed depending upon the fuel. Greater reductions are proposed for the larger units that are still less than 250 MMBTU/hr. The target cost level is in the range of \$4 - 5 K/ton NO<sub>x</sub>. A work group has been working with CIBO to attempt to understand the inventory and to improve the cost estimates. Another round of conference calls will be scheduled for the end of August. There will also be some committee meetings at the end of September.

Ann McIver of Citizens Thermal reported on the Industrial Perspective. The industrial sector encompasses the non-utility energy providers and, as a result, includes a wide variety of units and operations. While there are a number of potential benefits from reduced emissions, the question remains at what cost. For the industrial user, the number of customers is limited and the specific costs are higher. Stress due to job loss can cause heart attacks and death, today, not at some potentially distant time in the future. Because of the variety of boilers and control systems, the regulations end up being very complex. With the additional complexity, overlapping regulations begin to have impact. Reductions are accomplished by starting with engineering studies leading to cost estimates and purchasing decisions. Lead times and delivery become important. Installation of equipment presents a problem to industrial units as there is no steam grid. While fuel switching can be an option, cost and availability are not always feasible. Fuel variability becomes an issue, especially for alternate or waste fuels. Project funding is a significant issue. Pollution control projects rarely have a financial rate of return. These capital projects compete with other projects looking for funds. Replacement of equipment requires even longer lead times. In many states, permits are needed before contracts can be signed (implying the beginning of construction). For rule making, reliable data is critical. Go to the web sites and review the data for your plant. Realistic estimates of what can be accomplished are needed. Finalization of the rules for some significant period of time without overlaps would be preferable to bring some certainty to the process. Allowances for state of the art technology application would be another tool that could be used to increase innovation with fear of criminal prosecution for missing an emissions target.

Praveen Amar reported on NESCAUM's activity in air use programs. NESCAUM represents 8 states in the Northeast. The goal is to have more consistent regional approaches to air use issues. The CAIR rule will reduce criteria emissions by about 70% by 2015. This improvement will still not bring the region into attainment. This begs the question as to what else can be done. A project has been initiated to collect information on control technologies and experience for industrial boilers. With regard to the introduction of new technology, appropriate risk sharing is required. There are at least 4 parties involved in the deployment of new technology. These include the supplier, the

plant owner, the state, and the regulatory agency. Appropriate risk sharing amongst all 4 parties, including the regulatory agency would help the introduction of new technology.

## VII. Control Technologies - Fred Fendt

Kevin Snape, The Lubrizol Corporation, reported on emissions management for heavy oils through dispersion chemistry. For heavy oil firing, the use of additives can help reduce emissions and improve fuel economy. Heavy oil offers a savings of \$220/metric ton over distillate oils. Heavy oil is more difficult to burn and has more sulfur, ash, and other constituents. More maintenance and corrosion issues also add to cost. Additive technology can serve to reduce corrosion and improve efficiency. Additive materials include magnesium for sulfur control, iron for particulate control, and asphaltene stabilizers to minimize cracking. Lubrizol 9050 is a magnesium based additive system which allows heavy oil to be handled easily. For back end SO<sub>3</sub> corrosion, the additive at 950 ppm reduced the acid dew point down to 121 C. The particulate matter was reduced by over 60%. A water separation test showed that within 5 - 7 minutes all water was separated. Internal deposits are converted to fluffy ash that is easily cleaned. Opacity is reduced. Fuel economy was improved by 1%. SO<sub>3</sub> concentration was reduced by 95%. A modified product is being developed, which uses reduced amounts of magnesium, but adds some iron and calcium. This mixture offers somewhat higher fuel efficiency, with somewhat less SO<sub>3</sub> reduction.

Lew Hinman, UTC/Pratt & Whitney and Forney Corp., reported on progress with the ElectroCore Technology for particulate control. Since last year, a pilot unit has been constructed and tested. This technology has been supported by EPRI and Southern Co. as well as UTC. The pilot plant is located at the Gadsden plant of Alabama Power. The ElectroCore system precharges the particles and splits them into a particle rich and particle lean stream. The particle rich stream concentrates the particles into 10% of the gas flow, which can now be cleaned of particulates in a much smaller volume. The 90% gas stream is already lean with respect to particulates. Initial applications are intended to polish underperforming collection devices. The pilot unit is set up to handle 7,000 acfm (about 1.5 Mw). Testing began in the 4<sup>th</sup> quarter of 2005. About 300 hour of electrostatic operation and 900 hours of gas flow have been achieved. Initial data was somewhat below expectations. A misalignment of the pre-charger was determined to be the cause. After correction, the device consistently concentrated 98 - 99% of the particulates into the 10% gas stream. Particle sizes in the range of PM<sub>2.5</sub> were collected up to 99.9% efficiency. One round of testing was conducted with activated carbon for mercury collection. The particulate capture system handles activated carbon right along with the fly ash. Mercury capture was basically identical with EPRI reported results. During 2006, some SO<sub>2</sub> testing will be undertaken. A contract has been signed with an industrial unit in the mid-West. The plant has 3 x 18 Mw boilers. The first unit should be on line during the 2<sup>nd</sup> quarter of 2007. The BOP is being handled with a power industry A/E.

Richard Abrams reported on the RSCR technology from Babcock Power Environmental Inc. (formerly Riley Stoker). SCR technology typically operates that catalyst bed at

around 600 F. The BPE system uses Cormatech catalyst, which is an extruded honeycomb system. The typical SCR installation is located between the end of the economizer and the beginning of the air heater. The temperature range is typically 600 - 800 F. Such an arrangement puts all of the ash through the catalyst. For a WTE applications, the ash contained many poisons to the catalyst. Likewise, for wood firing, sodium, potassium, and arsenic are catalyst poisons. Finally, some units don't have room for the catalyst between the economizer and the air heater. As a result a "tail end" catalyst system was considered. The lower temperature gas (300 F) requires larger sizes, more heat exchangers, and somewhat lower NOx removal. This led to the development of the Regenerative SCR (RSCR). This system uses a regenerative heating system for the catalyst. Hot gas heats up the catalyst. The hot gas is switched off and flue gas is admitted with ammonia injection. The NOx is removed. The flue gas is sent down through the second bed, thus warming it up. The hot gas is turned on in the second bed to heat it up. The flue gas is admitted from underneath the second bed. With only 2 beds, there are spikes in the concentrations. A third bed has been added to smooth out the concentrations. At a 50 MW unit in Maine, 5 beds were used with 2 units converting NOx, 2 units, cooling, and one unit purging. With this system 80% NOx reduction was achieved. With the regenerative system, 95% energy recovery was achieved. The units are self contained. A 15 Mw unit and a 50 Mw wood fired unit have been in operation since the end of 2004. The ammonia slip level is 13 ppm.

Larry Day, Nationwide Boiler Incorporated, and Robert Remkes, CRI Catalyst Company reported on the CataStak SCR system. This system applies to smaller, gas fired boilers. Nationwide specializes in rental boilers. In California, rental units have to meet the same environmental standards as permanent units. For these units, a small catalyst system was developed to meet California standards. With the success of these rental units, the SCR system was offered to other stationary units. Current NOx emissions are 6 ppm. Over 30 units have been retrofitted. Ammonia slip is 5 ppm. CRI developed the catalyst to operate at temperatures below 300 F. CRI was originally part of Shell. The catalyst was developed for the European market. The catalyst is pelletized to provide high surface area and high porosity. The catalyst is supported on a stainless steel box in a lateral flow module. Pre-engineered systems are available for package boilers firing gas. The modules can be skid mounted. There are 7 standard sizes from 35 kpph to 300 kpph. Bottled anhydrous ammonia is used. The on site amount is limited to less than 500 lb, which avoids a number of safety issues. The usage rate is 1 - 1.5 lb/hr.

Patrick Polk, Halder Topsoe, Inc., reported on the SNOX process. The SNOX process is a combination of an SCR system and a wet sulfuric acid process. In this system, SO2 is recovered as sulfuric acid. The NOx is converted to nitrogen. The absorption processes are exothermic so that net heat is generated. With heat recovery, the plant efficiency can be increased. The equipment is sized for the gas flow rate. The higher the sulfur level in the fuel, the more heat is liberated and the more sulfuric acid is generated. No additional waste products result other than fly ash. The ammonia slip is oxidized in the sulfuric acid system. Very good particulate removal is required to protect the catalysts. The sulfuric acid is condensed in a glass tube condenser. This condenser is air cooled. The cooling air is subsequently used as part of the combustion air. NOx reductions are in the level of

90 - 95%. SO<sub>2</sub> removal is in the range of 95 - 99%. There have been 7 installations of the SNOX process. There was a DOE demonstration plant at the Niles Station of Ohio Edison (about 35 MW slip stream). The plant operated for 33 months in the early 90s. A final DOE report was issued on the DOE web site in 2000. ABB (Alstom) and Snamprogetti were part of the demonstration program. The sulfuric acid concentration ranges from 93 - 98%.

Kevin Moss, Tri-Mer Corporation, reported on the progress with the cloud chamber scrubber. Tri-Mer has over 16,000 scrubber installations of various types world wide. The cloud chamber is a wet scrubbing device, but has no internals. The key to the system is to put a very high charge on the water droplets. As particles get close to the droplets, an induced charge is created on the particle, which then draws it into the droplet. Three chambers are used altogether. A first chamber serves to saturate the gas and "grow" some of the fine particles. In the second chamber, a negative charge is imposed on the droplets. In the third chamber, a positive charge is imposed on the droplets to capture any particles that have an opposite charge. The first unit went into operation in 1999. A key point is that it is the droplets that are charged, not the particles. The water is recycled. The pressure drop is about 2 inches water gage. The power requirement is 8 watts/1000 cfm a multi-clone is used to collect the large particles. A pilot test was done at a university. A third party was brought in to measure emissions. The stack went from 0.65 lb/MMBTU at the boiler outlet to 0.008 at the CCS stack. Mercury removal was 89%. Chloride removal was 99%. SO<sub>2</sub> removal ranged from 40% to 98% depending upon pH control. Removal of 1.5 micron and smaller particles was 97.3%. Caustic or soda ash was used for pH control. The intended market for this system is small size units.

Jay Crilley, Mobotec USA Inc., reported on the Mobotec system. The Mobotec system is a multi-pollutant system looking at typical combustion products. The company was started in Sweden and worked mostly on industrial size units. In the US, the initial installations were for utilities, but industrial units have been in the market lately. The Mobotec system uses rotating overfire air (ROFA). This system mixes the overfire air as well as any material that is injected such as limestone. At a unit that burned bark and pulverized coal, the addition of the ROFA system improved the combustion efficiency, reduced the particulate matter, and improved the level of bark firing from 27% to 70%. With the overfire air, there are commensurate NO<sub>x</sub> reductions. With the addition of an SNCR injection (Rotamix), an additional amount of NO<sub>x</sub> reduction can be achieved. The Vermillion plant (CE unit) also showed an exit gas temperature drop of 30 - 40 F, which represents about 1% efficiency improvement. This increase in efficiency is offset by the fan power for the ROFA. The NO<sub>x</sub> level was reduced to 0.10 lb/MMBTU. There is also a CFB ROFA system. There is a lot of gas stratification in a furnace. At the cyclone inlets, the SO<sub>2</sub> concentration varied from over 600 ppm at one corner to under 60 ppm at the other corner. By adding the ROFA system, the SO<sub>2</sub> removal went from 92% removal to 97% removal while using less limestone. The NO<sub>x</sub> level was also reduced while using less ammonia.

Robin Oder, EXPORTech Company Inc., reported on the MagMill technology for emissions reductions with existing pulverizers. The goal of the technology is to get heavy particles out of the coal before it goes to the burner. Material is drawn from the bowl of a bowl mill. This material is passed through a magnetic separator. Any weakly magnetic material is rejected from the coal. The remaining material is returned to the pulverizer. A beta prototype has been operated on a Bradley mill in Allentown, PA at the 1.5 ton/hr capacity level. The power requirement for such a mill is reduced by 40%, as the hard to crush material is being removed. At 95% BTU recovery, significant amounts of mercury, sulfur, and ash can be reduced from the parent coal. The magnet power is about 4 Kwhr/ton. The capital cost is estimated at \$25/Kw for a 30 MW unit, leveling off at \$10/Kw after about 70 MW. The sulfur and mercury are both reduced.

Joep Biermann, MinPlus, reported on a non-carbon mercury sorbent. This sorbent is a multi metal material that works at high temperatures in a furnace. Production rate of this material is at 50,000 ton/yr. As long as the metal is volatile, the high temperature sorbent can capture it. The sorbent material is an activated kaolinite with calcium compounds. The surface area is 15 m<sup>2</sup>/g of wide pore material. The chemical analysis is similar to fly ash. The difference is that a chemical reaction takes place to lock up the mercury. The product forms a glass like structure that does not release the mercury except at very high temperatures. This material was injected along with a ROFA system at a CE unit. The capture rate was about 75% with 2 injection points. With 4 injection points, 97% mercury capture was achieved. Dispersion of the material is critical. The mercury was shown to end up on the fly ash. The mercury was bound to the silic alumina clay. Mercury mass balances were closed to within 5%. At another test site, the injection rate was about 3% of the ash rate. The mercury reduction was 80%. Leaching tests were done on the fly ash. Mercury leaching results were below the 0.2 ppb detection limit. Tests done at WE Energy indicated that the fly ash was still salable.

#### VIII. Fundamentals - The Science of NO<sub>x</sub> Control - Joe Comparato, Fuel Tech, Inc.

The nitrogen in the air that is used for combustion can be oxidized to NO at flame temperatures. The original mechanism was identified by Zeldovich in 1947. The reaction is highly temperature dependent. Attempting to maintain relatively low temperature conditions helps to reduce the formation of thermal NO<sub>x</sub>. Most solid and liquid fuels contain nitrogen in various organic compounds. This fuel bound nitrogen also converts to NO<sub>x</sub>. During the combustion process, a variety of intermediate compounds are formed which convert the NO<sub>x</sub> back to N<sub>2</sub> and O<sub>2</sub>. As a result, about 40% of the fuel bound nitrogen ends up as NO.

Control strategies include reduced temperatures, air staging, fuel staging, adding reducing agents, and combinations of the above. The addition of reducing agents, such as ammonia or urea typically have a temperature window at which they are most effective. This is due to competing processes. At the higher temperatures, these compounds behave more like fuel bound nitrogen. At lower temperatures, the reactions to reduce NO slow down. For SNCR, the ideal temperature is around 1850 F. Computer modeling is used to locate target temperature ranges along with adequate residence times in order to optimize

the SNCR Load following is handled by having multiple levels of injectors in addition to changing nozzle pressure and flow. SNCR can be used in combination with SCR. Any ammonia that is not reacted with NO is now used in the catalyst system to obtain additional NO<sub>x</sub> reduction. With the lower level of NO<sub>x</sub> coming from the SNCR zone, a smaller catalyst is needed in the back end. The choice of ammonia or urea is often based upon the safety and handling requirements.

#### IX. Annual ABMA Gas & Oil Fired Burner Manufacturers' Panel - Randy Rawson, ABMA

The panel members included Daniel Willems, Cleaver Brooks, Inc., Vijay Mandayam, Coen Company, Inc., Bill Testa, John Zink Company, LLC/Todd Combustion, and Ray Medina, Hamworthy Peabody Combustion.

Dan Willems focused on gas firing. For natural gas, the NO<sub>x</sub> is dominated by thermal NO<sub>x</sub> formation. Uncontrolled NO<sub>x</sub> is typically around 90 - 100 ppm. With proper fuel and air control in the burner, gas fired burners are being offered with 9 ppm NO<sub>x</sub> levels. Digester gas is dominated by methane, but has substantial amounts of CO<sub>2</sub> and water. There is also some H<sub>2</sub>S, creating a sulfur issue with the gas. Landfill gas is similar to digester gas. Town gas is more common overseas. This is also similar. Refinery gas, or hydrogen gas, has a fairly high concentration of hydrogen. Uncontrolled NO<sub>x</sub> for this fuel is in the range of 400 ppm. Waste liquids present additional problems in that fuel nitrogen is involved.

Vijay Mandayam presented some opportunity fuels for industrial combustion. Interest in opportunity fuels has increased with the price of conventional fuels. In addition to the gaseous fuels, there is a wide variety of liquid fuels such as bio diesel, glycerine, grease, tallow, solvents, and other organic wastes. Considerations include quantity of supply, fuel quality, reliability of supply, and fuel consistency. For many of these fuels, modifications are often required in the balance of the plant. Emissions levels need to be evaluated. This includes odor considerations as well as criteria pollutants. Other considerations include boiler maintenance/life, complexity of operation, capital expense, and ROI. Heavy oil produces twice the uncontrolled NO<sub>x</sub> as light oil. Hydrogen produces 2.5 times the NO<sub>x</sub> as natural gas.

Bill Testa reported on considerations for minimizing emissions. Major factors impacting emissions include boiler type and conditions, fuel types and characteristics, and controls. The major boiler types are water tube and fire tube boilers. Within the water tube boilers there are designs for fuel type, package boilers, tube wall configuration, and refractory levels. Water tube units have relatively large furnace volumes. Fire tube units have the flue gas inside the tube. Furnace volumes are much lower. There are often restrictions on flame length. For gaseous fuels, the NO<sub>x</sub> formation is dependent upon the combustion temperature. For liquid fuels, the fuel nitrogen has to be taken account of. There is also ash in some of the waste liquids. Although low by coal standards, they are often a factor of 5 or 10 times the levels of conventional fuel oil. The expectations are for stable operation, wide operating range, low emissions, low maintenance, and ease of

installation. Excess air rates must be maintained within 5% of the design level. A 5 degree change in air temperature changes excess air by 1%. Flue gas recirculation must also be held within 5%. A 25 degree change in FGR temperature changes the level by 1%. Stack draft impacts the level of FGR. Control schemes are essential to monitoring and controlling performance when fuels are mixed together and variable.

Ray Medina reported on auxiliary burners for boilers. Such burners are needed to supply additional heat or to stabilize operating conditions. When additional fuels are considered, control issues abound. Simple control systems are no longer adequate. For existing furnaces, furnace volume is fixed. This may result in unusual locations for burners. Residence time requirements vary for different fuels. Flame impingement is a serious consideration. Pressure drop may change due to swirl requirements of the burner. This can lead to fan changes. A burner is basically a mixer. Variations of mixing parameters due to fuel and emissions determine the pressure drop and flow requirements, leading to duct, windbox, and register requirements. Ignitors need to be included in the overall process review. Fuel viscosity is important for liquid fuels. When fuels are blended, it may make sense to have a small storage tank to facilitate the metering and blending of the fuels.

#### X. Case Studies in Boiler MACT Compliance

John DeRuyter, E.I. DuPont de Nemours & Company, reported on Dupont's Parkersburg facility. DuPont has 3 facilities that have coal fired boilers. The MACT floor basis for existing sources promotes control technology for the best 12% of controlled sources. Much of the data came from experience on utility boilers. For emissions, no coal-fired, spreader stoker data was available. The DuPont Washington Works has 6 coal-fired boilers that were installed from 1947 to 1965. These were arranged to have 2 boilers for one stack. These units all had some form of dust collection. Two of the dust collectors had experienced serious erosion problems. All bag houses were over 30 years old. Bag blinding and serious control problems are common. The as received analysis for the 43 coal samples showed that the average chloride was right on the border of potentially being in compliance. Mercury was similar. Independent lab analysis can include several errors. These include sample quality or contamination, procedural errors, and transcription errors. Initially, for chlorides, it looked like some control with emissions averaging could work. The mercury emissions test were contradictory. The old baghouses appeared to be getting no mercury removal. The old units had continuous pulsing which limited any ash cake build up on the bags. Exit gas temperatures were high relative to EPA data. Other differences further complicated the analysis. DuPont contacted GE Energy for the use of a small pilot plant for the GE MAX-9 system (electrostatically enhanced filter). The same coal was used for all tests. Constant boiler conditions were maintained. The pulse was set by pressure drop (from 5 to 6 in). Dry sorbent injection was also tested with both brominated and non-brominated activated carbon. Hydrated lime, trona, and a sodium sorbet were tested. Full gas analysis at the inlet and outlet was deployed. Several CEMs for the various gas were tested. Over 50 coal samples were analyzed. The chloride ranged from 0.10 to 0.19%. The mercury ranged from 100 ppb to 300 ppb. Dust collector ash ranged from 60 to 180 ppb. Carbon

in the ash, although relatively high, did not appreciably help the mercury collection. The baseline tests did not show much correlation between measured coal data to measured capture data. There was a very significant variation in coal properties over the 2 month test period. A total of 46 tests were run on the MAX-9 unit. At the inlet, there was some correlation with chlorine in the coal and chlorine in the inlet. With no injection, there was little collection of chlorine. With trona injection, 30 - 50% HCl reduction was achieved. SO<sub>3</sub> was reduced with either calcium or sodium injection. For mercury, the no injection case showed relatively little reduction compared to the inlet. The activated carbon injection ranged from 40 - 60%. Combined activated carbon with lime injection gave reduction rates from 70 - 95%. Carbon injection impacts electrostatic performance. Sorbent injection directly impacts pressure drop. The ash cake provides the residence time for reaction. SO<sub>3</sub> presence in the flue gas inhibits mercury capture. Bag blinding was relieved by the reduction in SO<sub>3</sub>. The hydrated lime improved the mercury capture by reducing the SO<sub>3</sub>. There was no difference between brominated and non-brominated activated carbon. The injection of lime, lime/carbon, and trona all resulted in a reduction of chlorides. Baghouse upgrades are planned for 4 of the boilers. Two units will get new baghouses. Sorbent injection will be used for assuring chloride and mercury reductions. The mercury CEM failed. Explanations range from SO<sub>3</sub> blinding to volatile organic interference.

Robin Ridgway, Purdue University, reported on Purdue's Wade utility. The plant provides all of the heating steam, chilled water, and cooking steam for the campus as well as 41 Mw of cogenerated electricity. There are 4 units of about 280 MMBTU/hr. Two are stoker fired and one is a CFB. The remaining unit is a backup oil/gas fired unit. The funding issues for a university require significant lead times in order to meet the compliance deadline. The plant assessment indicated that most of the pollutants were ones that were not really considered (or measured) in the past. As a result, data was needed. The variability of the coal for mercury and chlorine was considerable. Stack testing was done to give some idea of mercury emission rates. An engineering consulting firm was hired. An attempt was made to do mass balances on mercury with little success! (due to variability). For compliance planning, the mercury level was selected at 9 - 15 lb/TBTU. The chloride level ranged from 30 to 400 ppm. For the CFB, the particulate, mercury, and chloride were below the MACT limits. The stokers had 9 lb/TBTU mercury emissions. The particulates ranged from 0.1 to 0.6 lb/MMBTU. The chloride levels were below the MACT limits. Fuel analysis was selected as the compliance method. For the stokers, new fabric filters will be added to each stoker to replace the old precipitators. Emissions averaging will be used for compliance on the stoker units. The air heaters would also be upgraded as the exit gas temperatures were above 370 F. The final plan avoided the air heater upgrades would be replaced with a flue gas spray cooling system. With emissions averaging, only one of the units will get the new bag filter. The CFB can be averaged with the 2 stoker boilers. The plan was averaged by the state. Natural gas firing may be needed for high loads. The baseline testing was key to understanding the fuel and the boiler. Compliance alternatives need to be reviewed. Older units present a challenge. Emissions averaging is helpful in reducing overall capital costs. The health based option is quickly disappearing as the submittal date is due in September. Other rules and regulations need to be considered as they

impact equipment decisions. For state universities, the legislature and the board of trustees have to approve the expenditures. This caused a delay of about a year. Since the bids were selected and the contracts awarded, there have been delays due to equipment lead times getting longer. There is now serious concern that the compliance date cannot be met. Consideration is being given to requesting an extension for compliance.

Mick Harris, Ohio University, reported on the MACT compliance with the Fluesorbent Injection technology. Ohio University has been working with Sorbent Technologies for a demonstration project with OCDO in Ohio. The total student population is 28,000. The university is over 200 years old, with many buildings over 100 years old. The university has continuously used Ohio coal since its founding in 1804. The annual utility budget is over \$10 million. The Lausche heating plant has 4 boilers with 3 x 70 kpph stokers and a 120 kpph natural gas boiler. One stoker has a natural gas burner for load swings during the annual maintenance period. The coal boilers were installed in 1966. The gas boiler was installed in 1995. Infrastructure competes with educational needs for funds. Infrastructure is not pretty. The project strategic objectives were to demonstrate an SO<sub>2</sub> reduction process with no waste by-product, demonstrate an economic process for smaller boilers, and demonstrate load following capability with high reliability. The Fluesorbent duct injection technology uses hydrated lime on an expanded perlite substrate. The target performance was 85 - 90% SO<sub>2</sub> removal at all loads, load following from 30 kpph to 140 kpph, and coal sulfur up to 4%. The by product will be used as fertilizer. The project will retrofit 2 of the stokers with upgrades and new bag houses. These will also be retrofitted with the Fluesorbent system. New ID fans were added to take care of the additional pressure drop. The hydrated lime absorbs SO<sub>2</sub> in the duct. The expanded perlite holds water, but has a dry consistency. The original schedule called for a 30 month project. They are now in month 100. Mechanical completion occurred in 2003. Startup issues delayed the start of testing to 2005. The test program will be completed in 2007. The on site cost is now estimated at \$5.5 - 6.0 million. The bag house portion is \$1.7 - 2.0 million. The local coal is currently delivered at \$55/ton. The coal is 2.3% sulfur and 6.4% ash with 12,300 BTU/lb. The emissions test indicated that levels are low enough to qualify for area source consideration. At a Ca/S ratio of 2, the SO<sub>2</sub> removal has been 70 - 75%. Additional testing is planned to achieve a closer approach to saturation and a lower gas temperature, which will improve the SO<sub>2</sub> removal. The mercury removal from the gas was over 70% in recent test.

## XI Efficiency & Combustion Optimization

Jeff Mais, Benz Air Engineering, Co., Inc. reported on the Benz Air emissions reduction system. by emphasizing repeatable air flow control and accurate fuel flow measurement, close air control can be matched against fuel flow to achieve low excess air operation. The fan curve characteristic is used to identify the stable operating points for the fan. A variable frequency drive is used to match air flow to fuel flow. With this close matching, much higher turndown can be achieved. With lower excess air, lower NO<sub>x</sub> can be realized. The simple payback on this application ranges from 1 - 1.5 years. Flue gas recirculation can be added for additional NO<sub>x</sub> control. With one 50,000 lb/hr unit, with

FGR, the NO<sub>x</sub> was 0.019 lb/MMBTU with 0.9 % XS O<sub>2</sub>. Turndown was 25:1. CO levels are in the range of 100 - 200 ppm at the low excess air.

Randy Morrison, Automation Applications Inc, LLC, reported on advanced controls for biomass fueled boilers. The project was at a large pulp mill in Western Canada. The 2 power boilers provide 700 ton/hr using bark and supplemental gas. Some paper mill sludge was also used. The customer wanted to reduce the variability of the steam flow, improve efficiency, keep particulates within emission limits, and work through “legacy” operating procedures. By improving the combustion controls, the control of fuel and air was improved. The excess air was then reduced from 7% to about 3%. Separate controls for bark and gas were added. The strategy for energy management is to allocate steam demand amongst boilers based on minimum cost, while adhering to equipment constraints. Internal fuel sources should be maximized. Steam distribution should emphasize power generation. A rule based supervisory control system was deployed. Load decisions are made in direct response to header pressure fluctuations. After all of the changes to the control system, the overall efficiency improved by roughly 5%.

## XII. Continuous Emissions Monitoring & Compliance – Moderator -- Bob Davis, Scott Specialty Gases, Inc.

Bob noted that inaccurate calibration gases can be costly. EPA does blind audits. Nearly half of the calibration gases failed. SCR systems use NO<sub>x</sub> monitors at the inlet and outlet of the catalyst. On average, it takes 22 lbs of ammonia injection to reduce NO<sub>x</sub> by 1 ppm in the average combined cycle plant. If the calibration gas shows a high number at the inlet, extra ammonia is needed. For coal-fired units, the inlet number is at a generally higher level such that a 2% error results in up to 6 ppm high reading. This could result up to a \$50 K/yr cost in excess ammonia.

David Vojtko, Horiba Instruments, Inc., reported on the purposes of emissions monitoring. These include verification of performance, demonstration of compliance, and participation in trading allowances. Permit levels are looking at less than 10 ppm levels for NO<sub>x</sub>, CO, and NH<sub>3</sub>. Inaccurate measurements could lead to loss of credits or result in fines if a standard is “violated”. Monitoring systems are the last item to be purchased, but the first item to show a violation. With tighter emissions requirements, more sophisticated monitoring systems are required. Present day analyzers show accuracy in the ppb range. New systems have fewer moving parts and are microprocessor driven. Modular design of detectors allows for multi gas analyzers.

Mike Cybulski, METCO Environmental, gave a presentation on the total costs of Boiler MACT stack testing. There are hidden costs in any stack testing project. There are often “soft costs” that need to be taken into account. The types of hidden costs include project postponement, extra work, pre-test preparation with state personnel, supervision, report reviews, accidents, and unnecessary permit violations. Some companies have good reputations with state agencies. Checking with the state agency about stack testing companies can minimize pre-test meetings. Experience is a key factor in the execution of

the testing and the subsequent report preparation. In preparing an RFP some types of questions that might be asked include:

What are cancellation costs?

What are overtime costs?

What is the project manager experience?

What is the education level of the crew?

What is the percentage of part time help?

Is the EMR under 0.9?

Are field personnel HAZMAT trained and DOT compliant?

What is the turnaround time of the report?

Who prepares the report?

Quicker turnaround time on reports allows more time to take corrective action ahead of the deadline. The more experienced the report writer, the less likely the frequency of errors. The greater the number of crews, the more flexibility in meeting schedule. The greater the experience and the education of the crews, the better the potential for adapting to difficulties. A complete evaluation of the companies will improve the likelihood of having a satisfactory testing experience.

Dan Todd, Air Quality Services, LLC, provided information on the understanding of stack testing precision. There is inherent variability in stack testing. Sampling methods include manual methods and instrumental methods. For most manual methods, wet chemistry is used to quantify concentrations in the stack. Method 1 is for determining sample location. If drawings are used, it is necessary to confirm their accuracy. Method 2 is for measurement of stack gas flow. There is significant opportunity for variability in flow measurement. The sources are cyclonic flow, nozzle location, manometer reading, and personnel differences. Method 3 covers the oxygen or CO<sub>2</sub> concentration. The sample is collected in an inert bag. A wet chemistry analysis is performed in a laboratory. Variability arises from reading the sample volume and laboratory procedure differences. Method 4 covers the moisture concentration in the stack gas. Variability arises from sample recovery. Method 5 specifies the measurement for particulate matter. The sample is collected on a filter at 250 F. Typically there are 3 sample runs of 1 hour duration. Traverse testing is required to obtain a full cross section of the particulates. The particulate must be drawn into the pilot tube using isokinetic sampling. This method attempts to match the gas velocity in the stack at the sample point with the sampling velocity. This is difficult. EPA allows a 10% error range. Further, once the sample is collected, the sample is on a filter paper which must be isolated and sent to a lab.

Weather conditions, etc. could affect sample recovery. Method 26 covers chlorides. There are interferences with this method including ammonia. Method 19 covers the determination of heavy metals. Sample recovery is more of an issue as the concentrations are usually very low. Flow into impingers presents another source of variability. In addition to all of these sources, there is the natural availability of the fuel, the process variability, logistical variability, and analytical variability. The stack test is a snap shot (as opposed to an integrated average over time). These sources of variability are all “normal”. To help improve the situation, consider longer sample runs, use more sample points, and set up on site sample recovery (and analysis), try to run at steady state on the day of the test. Allow enough time for testing. A plant radio for the test crew is helpful.

Bill Worthington, Sick Maihak, Inc., reported on CEMs for Boiler MACT. For continuous monitors, there are a variety of types and methods that automatically attempt to measure a particular compound. Sampling can be extractive, in situ, or remote. CO and O<sub>2</sub> are amongst the more easily measured compounds than mercury and chloride. Practical considerations include access to the sample point, access to the analyzer, location of gas cylinders, safety issues, maintenance, and sample location. The sampling interface includes consideration of dilution, particulates, moisture, and sensitive analyzer. The in situ systems do not require a sampling system, but are often expensive due to materials due to corrosion and temperature issues. Dilution is accepted for NO<sub>x</sub> and SO<sub>2</sub>. There is also a data acquisition system that must produce the reports that the regulatory agency requires. In order to plan a system, the stack temperature, particle size/distribution, gas composition, gas velocity, and sample location (with operational practices) should be known (or reasonably well estimated). Heated sample lines offer many opportunities for error. Follow the manufacturer’s directions and spend adequate time to assure that these are installed properly. NDIR is still the standard for CO. The paramagnetic analyzer is also the standard for O<sub>2</sub>. In situ systems are more common for opacity. These can be point systems or single or double pass. For opacity, double pass system is used. A point system with a retro reflector can measure other gaseous compounds. One of the disadvantages of the in situ systems is that it is much more difficult to add another detector (for another gas requirement). Method 10 has been changed to include an interference test. Manufacturers have to issue a certificate. The sum of the interferences can be no greater than 2.5%. Built in test features are desirable, such as zero and span, contamination check, and linearity.

Seth Morrell, Altech Environmental USA, continued the CEMs theme with the elements of the system. The opacity analyzer, the flow probe, and the sample probe are all at the stack. Signal cables and flow umbilicals bring the sample or data down to the analyzers and the data acquisition system. Extractive sampling is the most common for compliance monitoring. For multi-component analyzers, infra red technology can handle up to 10 continuous gas measurements. The advantage is that much less space is required compared to individual analyzers for each gas.

XIII. Stoker Fired Boiler Workshop - Bill McPherson, DTE

Bill McPherson, of DTE Energy Services, gave a presentation on fuel supply and service opportunities. Most of the opportunity fuels have been available in the past. What is different is the cost of conventional, high quality. While oil and gas have garnered much of the headlines, coal and petroleum coke have also seen price increases. As ethanol has been dubbed as some kind of substitute for gasoline, the price of ethanol has also increased. Biomass can be utilized in fluid beds or gasified into gaseous fuel or products. Stokers can utilize a wide variety of fuels. Large industrials are better suited to utilize these fuels as they are large energy users with experience in handling materials. Developments may lead to briquetted waste fuels, fuel broker,

Bob Morrow, Detroit Stoker Company, reported on “Getting the Most Out of What You Have.” For this presentation, existing spreader stokers firing coal were surrogate for “what you have”. Most of these units were designed for a coal specification. When an alternate fuel is considered, up to 10% of this fuel on a BTU basis can usually be mixed with the coal without serious degradation. The combined fuel mix should have a heating value of at least 7500 BTU/lb. High moisture content causes increased gas flow. High nitrogen content (>0.5%) gives concern for NO<sub>x</sub> levels. The introduction of a coarse, higher moisture biomass fuel will typically result in a slight reduction in NO<sub>x</sub> and an increase in CO. The introduction of a fine, dry fuel results in a slight increase in NO<sub>x</sub>, with little change in CO. Alkali content impacts the slagging and fouling characteristics of the ash. As a guide, when the alkali content exceeds 0.4 lb/MMBTU, slagging and fouling issues arise. Mixing, metering, and distribution are the factors that usually have the most impact on the utilization decision. With the lower heating value fuels, larger mass flows and volumes of fuels are needed. Feeder systems are impacted. Dust can be injected pneumatically in between the coal feeders. This type of fuel can act as a reburn fuel, provided that there are no slagging and fouling issues with the fuel. From a cost point of view, a figure of \$30/ton into the boiler is a guide for cost-effectiveness. Emissions need to be considered. Feed considerations are critical.

Keith Moore, Phenix Limited, LLC, presented results from a stoker fired boiler retrofit using gasification. The technology uses a hybrid gasifier in front of the stoker to reduce operating cost and emissions. The technology is based upon work done on the Rockwell burner for low emissions. Recent developments have been packaged together to create a system with the trade name “Clean Combustion System”. Adding back end equipment is costly. The goal of the CCS technology is to work on the front end of the system by working on the sulfur at the burner level. A demonstration unit in Canada operated with SO<sub>2</sub> levels of 0.2 lb/MMBTU and NO<sub>x</sub> at 0.15 lb/MMBTU. In the process, the coal is fired at very low stoichiometry with limestone in a refractory burner. The operating temperature is high enough to slag the ash. In the reducing atmosphere, any NO<sub>x</sub> that is formed is reduced. The reducing gases are introduced into the existing furnace. As the gases cool, over-fire air can be added at temperatures that minimize the formation of thermal NO<sub>x</sub>. The sulfur in the coal ends up in the slag, bound up in the refractory matrix. This sulfur does not leach out of the matrix, allowing for landfill disposal. The project retrofit in Illinois required a reduction in cost and emissions by 50%. The stoker was importing stoker coal because of sulfur limitations. The retrofit will allow the use of local coal. An indirect system is used to pulverize coal. Powdered limestone is added to

the mill. The stoker feeders were removed. The bottom was bricked up. The slagging burner and slag tank were added. A closed loop heat transfer system was added for air preheat. The cost of local coal is 60% lower than the imported coal. The plant efficiency is expected to improve by 10 points. SO<sub>2</sub> removal is expected to be in range of 90%. The estimated hardware cost was around \$4 million (without installation) on a 125 kpph unit.

Carl Bozzuto, Alstom Power, Inc. (Retired), presented a review on slagging and fouling in stokers. Key elements of concern are alkalies, chlorides, sulfur, lead and zinc, ash content and moisture. The alkalies form low melting compounds that are aggressive in terms of corrosion. These form initial deposits on tubes as low melting salts. These sticky deposits attract other materials that impact the tube and stick to salt, increasing the deposit rate. Potassium is more aggressive than sodium. Chlorides attack the metal at weak points in the steel. This type of attack is highly localized and typically in the higher temperature materials. Sulfur can be detrimental, particularly in reducing zones. These can occur around burners and feeders. The resulting deposits cause sulfidation of the metal. Higher sulfur levels typically result in higher SO<sub>3</sub> levels which condense in the back end of the unit causing sulfuric acid attack on the metals. Lead and zinc tend to form very low melting eutectic compounds (as low as 600F). These deposits tend to be the most aggressive in terms of corrosion. These elements are more common in waste materials, such as MSW or construction waste. The ash content impacts the amount of material that has to be handled, both going into and out of the boiler. Increasing the ash content increases the deposition rate of deposits in the furnace. Moisture increases the gas weight and volume. This impacts the gas velocity in the unit as well as the fan issues. In some instances, the corrosion mechanism is one of forming a corrosion product that is removed by the gas, exposing fresh surface for corrosion. The increase in velocity accelerates this process. Aside from avoiding these fuels, there are some control measures available. Walls can be coated to avoid corrosion. Bauxite and/or silica can be added to tie up the alkalies. The overfire air system can be upgraded in order to minimize reducing zones or high temperature zones. With careful evaluation and selection, many of these slagging and fouling problems can be avoided.

Neil Johnson, Detroit Stoker Company (Retired), gave a presentation on alternate fuels on the grate of a stoker. These fuels can be burned alone or in combination on the 3 types of grates, which include traveling grates, oscillating grates, and water cooled oscillating grates. The latter is used for waste to energy units. The chain or traveling grate can burn only small percentages of alternate fuels. Biomass fuels have been burned for a long time. Bark, wood waste, kiln dried wood waste, bagasse, and agricultural waste have been utilized. Detroit Stoker has over 7,000 ton/hr of biomass utilization units in the world. Additional fuels include demolition waste, shredded tires, petroleum coke, industrial wastes, and process sludge. Many alternate fuels have higher volatile release than coal. This impacts the flame travel and the furnace volume. Taller furnaces are needed compared to coal. This will limit the amount of alternate fuel that can be co-fired. The keys to good operation include even distribution of fuel, even distribution of air, and proper utilization of over fire air. Feeding alternate fuels gives cause for concern in obtaining even distribution, particularly if the fuel is vastly different from the coal.

Mixing the fuel with the coal can avoid this problem, but many fuels are not conducive to this approach. Mixing in the coal bunker is possible, but many fuels hang up in the bunkers, which limits their utilization. Over-fire air should be upgraded to account for the higher volatile matter, reduce the emissions of NO<sub>x</sub> and CO, and reduce excess air. Flue gas recirculation can be used to help cool the grate and to help reduce emissions. Each facility and each boiler needs to be evaluated for the type of fuel being fired.

#### XIV. Workshop Discussion - Bill McPherson

One of the questions was high sulfur in alternate fuels. High sulfur petroleum coke was mentioned. One test had corn syrup which was reported to have higher sulfur. Another case reported a waste liquid from ethanol processing that was high in sulfur. Tire derived fuel has about 1.2 - 1.5% sulfur. The chopped tires can cause problems in CFBs. The traveling grates have been able to handle the TDF. For NO<sub>x</sub> control on stokers, overfire air and flue gas recirculation are the initial weapons for control. Up to 30% overfire air can be deployed. Grate cooling and sulfidation are concerns. There is limited experience with SNCR and SCR on stokers. Monitoring the grate temperature is helpful in controlling the air split. In a coal unit, the static part of the grate can be monitored with thermocouples. Experience indicates that the static grate is about 100 F cooler than the top of the grate. Reinjection of ash for reduced carbon loss. One user indicated that reinjection was not used because of fines and the baghouse. Larger particles were desired to form the filter cake in the baghouse. It was pointed out that if the bags were pre-coated and pulsed properly, the pre-coat forms the filter cake. There was no need to take steps to encourage larger particles to form the cake. Over pulsing removes the filter cake and reduces capture effectiveness. Carbon in the ash is relatively low in stoker bottom ash. The bottom ash is normally 80 - 85% of the ash. Fly ash can have much higher levels of carbon, especially when low ash fuels are used. Fly ash re-injection can reduce this carbon level. However, since the fly ash is normally low, the total amount of carbon loss is not great. High moisture levels increase product gas weight, as well as delaying combustion of the fuel until the water evaporates. One of the limits on moisture level (for sludges and liquid wastes) is the amount of water that can be evaporated while still having time to complete combustion. Bob Bessette suggested that CIBO start a survey similar to the fluid bed survey be initiated for solid fuel boilers (non fluid bed). The survey information is used to stimulate ideas for discussion at the fluid bed conference. A survey for non fluid bed solid fuel boilers could contribute to sharing of best practices amongst CIBO members for stokers and industrial PC units. Some immediate suggestions were to include ash fusion and softening temperatures. In addition, the efficiency information should take into account co-generation and boiler efficiency. Fred Fendt will email interested members concerning the survey to develop a suitable framework. Technical papers on emissions control for stokers can be sent to Bob Bessette for posting on the CIBO website. Topics for discussion were collected. The Technical Committee will be reviewing the list for potential activity. There was also a suggestion that a wider community of stoker users might be brought together to discuss common issues and problems.