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I. Trinity Compliance Workshop - Christi Wilson, Trinity Consultants

The Industrial Boiler MACT has been re-proposed, along with a solid waste definition (as opposed to fuel). GHG regulations and legislation are being proposed. Changes to the National Ambient Air Quality Standards are also being proposed, along with some changes to the New Source Performance Standards.

The new MACT rules were proposed on June 4, 2010. Simultaneously, the definition of solid waste, the Area Source MACT, and the Incinerator (CISWI) rules were also proposed. These are all due to be finalized by Dec. 16th, 2010, a court ordered date. An Area Source is a source that does not qualify for a major source (10 ton/yr of any one HAP or 25 ton/yr of a combination of HAP).

For major source, existing units, the standard is prescribed as the average of the best 12% of existing units. For new units, MACT is the best comparable unit. Fired boilers and process heaters are included under the rule. Waste heat boilers are not included. For area sources, units that switch from natural gas for coal or biomass would be considered new units. There are very few exemptions. Units combusting solid waste fall under the incinerator rules rather than the boiler rules. Units that would come under another MACT would be exempt from Boiler MACT.

The new rules are more stringent that the original rules vacated in 2007. Most of the standards have dropped by 2/3 or more. There are now 11 sub categories including PC, stoker, and fluid bed designations for both coal and biomass firing. There are also liquid fuels and two levels of gaseous fuels. There are 5 categories of HAP: mercury, non-mercury metals (PM), non metal inorganic (HCl), non dioxin organics (CO), and dioxin/furans. For units less than 10 MMBTU/hr, work practice standards are being proposed. This includes biennial tune ups, implementation and documentation of tune-up practices, reporting, and measurement and reporting of CO. There will also be a one time energy assessment of boiler systems. Assessments must be conducted by “qualified personnel” and be performed in accordance with “Energy Star” guidelines. All energy consuming systems must be identified. “Cost effective” energy conservation opportunities must be identified. No implementation of the energy savings is required. Start up, shut down, and malfunctions are not excluded from the rule. The rule applies at all times. Averaging only applies to existing sources in the same subcategory. An emissions averaging plan must be submitted. A 10% discount factor is applied. Thus the averaged units must meet a standard that is 10% lower than a single unit standard.

Testing requirements include a stack test for filterable PC (Method 5 or 17), for mercury, and for the others. Three runs of 4 hours each must be run. All tests must be conducted annually. All test results must be submitted to the EPA Emissions reporting tool. Fuel analysis can be used in place of stack testing for mercury and chlorides. Daily records must be kept to show that a new fuel has not been introduced. Monthly fuel analysis must be reported. Monitoring requirements include performance parameters that are established during performance testing. These are aimed at demonstrating that control devices are working (ie pressure drops, pH, voltage, etc.). For coal, biomass, and oil fired units over 250 MMBTU/hr CEMS systems will be required. For units over 100 MMBTU/hr, a CO CEMS will be required. Key reporting requirements include initial notification (within 120 days of applicability), notification of intent to conduct a compliance test, test results, and annual test results. For HCl and Hg, calculations from fuel, etc. are required. Reports must be kept for 5 years.

The Area Source category does not include process heaters. There are only 3 subcategories: coal, biomass, and oil. Gas is not included except if oil fuel is used as a back up (depending upon the percentage of time used or curtailment situations). EPA has established MACT for mercury on coal and GACT (Generally Achievable Control Technology) for biomass and oil. Similar provisions for chlorides and PM. Stack testing is required for initial compliance. Documentation of tune up programs and the energy assessment is required. Monitoring requirements include opacity monitors and performance parameters. Area sources greater than 100 MMBTU/hr will need a CO CEMS. Notification and Record Keeping are similar to Major sources.

EPA is requesting comments on the proposed rule. Specifically EPA asked if more subcategories are needed, if health based compliance is applicable, about work practice standards, and about reporting requirements. A number of industry groups have been drafting concerns and comments. For the most part, many of these concerns are similar. Variability of operation and fuel supply have not been adequately taken into account. The standards need to be met at all times, but the testing that generated the data was generally at full load for a limited period. The monitoring and testing cost estimates appear to be dramatically under estimated. The number of affected sources is also underestimated. The retrofit costs of control upgrades are also of concern, particularly for process heaters. Emissions standards for gas units fall under a Gas1 or Gas2 category. Some comments have suggested that only one category should be used. Practical and technical considerations of CEMS were not thoroughly considered. Energy audit costs were underestimated. Meeting the standards during SSM does not appear to be practical. Some comments on the use of surrogates have been proposed. There seems to be support in industry for including the Health Based Compliance Standard. Concerns were expressed about meeting all of the standards simultaneously in one unit. Comments have to be submitted by August 23, 2010. All relevant documentation, scientific reasoning, economic analysis, etc. must be included to defend/demonstrate/prove the point of the comments.

The proposed definition of solid waste is important because a unit that burns any solid waste would be classified as an incinerator under Section 129 of the Clean Air Act (CISWI). Section 129 requires control of multiple pollutants regardless of size. The standards are also more stringent. Environmental groups prefer to have more units regulated under CISWI. Under the new definition, traditional fuels (coal, oil, and gas) are not considered wastes. Materials that are generated within a facility and used within the facility are not considered wastes (subject to legitimacy criteria). Material that has been "sufficiently processed" could be considered a fuel. Drying or size reduction is not considered to be "sufficiently processed". Non hazardous secondary materials are not wastes if they remain in control of the generator (ie they are not discarded). The legitimacy criteria include being handled as a valuable commodity, has meaningful heating value (5000 BTU/lb), recoverable of meaningful energy, and contains contaminants at a level comparable to commercial fuels. "Clean" biomass is a "traditional" fuel. A petition process has been established for materials that are used as a fuel, but are outside the control of the generator. The basis for the petition is that material has not been discarded and is essentially indistinguishable from a comparable fuel. Tire derived fuels, TDF, where the steel belts and wires have been removed, can be sufficiently processed to qualify as fuel. Painted wood, treated wood, whole tires, off spec used oil, sewage sludge, coal refuse, and contaminated construction/demolition debris have been called out as solid waste. Qualified facilities that have certain agreements would be allowed to continue. All discarded materials that did not meet the legitimacy criteria would be considered wastes.

Greenhouse gas activities include proposed legislation and issued and proposed regulations. All of the regulations are based upon carbon dioxide equivalent. This includes all 6 of the designated greenhouse gases. The reporting threshold is 25,000 metric tons/yr of CO_2. This is the equivalent of a 57 MMBTU/hr natural gas unit. There are 4 ways to get into the reporting program. There is an "all in" category, which includes most utility and industrial operations. There is a limited applicability source that has to evaluate the annual emissions. Stationary combustion sources are a separate category. Finally, there is a supplier category (those that make GHGs, etc.). April 1, 2010 was the date required for having a monitoring plan for GHGs. Jan. 30, 2011 is the due date for a Certificate of Representation for Designated Representative. This is the person for each site that will be the contact for EPA. March 31, 2011 is the due date for installation of the monitoring systems. EPA does not intend for the calibration requirements of subpart 98 to apply to units that are allowed to use company records to quantify fuel usage and then CO_2. Fuel used for space heaters and other small sources are included under the stationary source category. The use of HHV data and carbon content data need to be based upon calculations from an approved test method.

There are 4 tiers of reporting requirements. One concern was gas flow meters that use orifice, nozzle, and venturi meters would need temperature and pressure measurements to correct the flow rate. EPA has revised and re-proposed a number of the subparts as a result of the comments. EPA plans to reissue these by the end of the year. There is a subpart for CO_2 injection and geologic storage. Subpart W impacts the petroleum and natural gas industry and covers fugitive CO_2 and natural gas emissions from wells and pipelines. At issue is the definition of a "facility". EPA has proposed that wells in the same basin should be aggregated as a facility. This could be thousands of wells, for example, in the Marcellus shale.

GHGs have become a regulated pollutant with the issue of the light duty vehicle rule. The LDV rule applies to 4 of the 6 GHGs. The rule was issued in April and became effective in July. The Tailoring Rule was issued on May 13, 2010 in order to address the problem of major source threshold for PSD and Title V. The existing threshold is 100/250 ton/yr. This would be a 200,000 BTU/hr burner. In order to avoid the problem of trying to address all of these sources, EPA raised the threshold for GHGs to 75.000 ton/yr. This rule allows for net change in GHGs. Thus, if an existing facility made a modification that caused an increase in GHGs on a net basis of 75,000 ton/yr, the facility would trigger PSD.

The start date is July 1, 2011. An existing unit that would not trigger PSD for other criteria pollutants would have to start construction before that date to avoid triggering PSD for GHGs. For Title V, the trigger is at 100,000 ton/yr. The first step does not include existing permits before July 1, 2011. By July 1, 2013, EPA can lower the threshold to 50,000 ton/yr. They must also determine whether a further reduction is needed for 2015 or 2016. There were no PSD applicability exemptions. Also none of the permit streamlining suggestions were included through step 2. No BACT guidance was issued with the rule. EPA has assembled a BACT task force. EPA anticipates issuing technical guidance by the end of the year. Energy efficiency appears to be the most likely criteria for GHG emissions. EPA has estimated that 14,000 existing facilities would now need Title V permits (greater than 25,000 ton/yr). Existing major sources (already subject to Title V) expect minimal impact. At renewal, GHGs will have to be considered. No amendments for Title V fees have been proposed, but each program must review their resource needs and increases can be expected. EPA will use FIPs (federally implementation plans) and federal Title V authority to ensure GHG compliance.

With regard to permitting, early planning allowing extra time will be needed as there are potentially massive unknowns. A phase II report on BACT for GHGs is due out from EPA. A wider scope is being reviewed including trading, supply chain improvements, and other potential options. The phase I report agreed that GHG BACT should apply to new and modified units that are subject to PSD. There was no consensus on things like location considerations (for things like storage) and other operational aspects. White papers are expected this summer on a number of industrial sectors. In a recent permit in California for a 612 Mw natural gas combined cycle plant the BACT determination concluded that a high efficiency power plant was the only available option and that a net plant heat rate of 7750 BTU/Kwhr (HHV) was set as the upper limit. There was also a plant in Idaho looking at BACT.

Cap and trade has lost momentum in Congress at the moment. Efficiency and renewable standards in an energy bill are still a possibility. The SEC has issued guidance on climate change related liabilities with regard to financial reporting. Any costs that might be incurred to mitigate emissions or purchase credits may need to be disclosed. Potential physical impacts from climate change that may impact a business (flooding, sea level rise, etc.) may need to be disclosed. Plants should determine their potential CO2(e) emissions in order to understand their potential requirements. Tracking Congressional and regulatory activity is a requirement. A long range carbon management plan or strategy should be developed so that many of these issues can be addressed.

EPA has proposed revisions to the National Ambient Air Quality Standards for NOx, SO2, and Ozone. The NO2 standard is being revised from an annual standard to include a 1 hour standard of 100 ppb. This new standard is very low and will be difficult to meet. Even emergency generators have had difficulty due to the modeling effort that is required to show that the 100 ppb standard can be met. The SO2 standard is also being modified to 75 ppb. The monitoring network will be modified by 2013 to improve the ambient monitoring. The current ozone standard is 75 ppb on an 8 hour basis. This is being revised downward to 60 - 70 ppb. Revisions to particulates and CO are expected this fall.

II. Stoker Workshop – Robert (Bob) L. Corbin, CIBO Member Service Consultant

Bob reported on the results of a stoker survey on the types and fuels for stokers. This was being done in response to member comments, with consideration being given to making this an annual survey similar to the fluid bed survey. Top reasons for outages were tube leaks, grate problems, ash pluggage, controls, fuel feed, ash handling, and particulate control. Going forward, the types of questions for both surveys are being compared. The results would be posted on the web site. One of the issues is the future ability to meet the proposed regulations for existing stoker fired boilers. Most of the owners have had these boilers for a number of years and know how to operate them. However, the new regulations are particularly stringent (by definition, at least 94% of the units don't meet them). Learning about how these units can possibly meet these regulations can be important. Suggestions included a webinar or a blog. For owners, the survey is on line at the CIBO web site and members are encouraged to check the web site and fill out a survey.

III. Concurrent Forum Discussions - Fred Fendt, The Dow Chemical Company, Moderator

Ann McIver of Citizens Thermal reported for the Owners' Forum. The owners first considered alternative fuels. Getting the alternative fuels in a form that can be handled and delivered to a boiler is a challenge. Many of the pelletized or chipped fuels cannot stand up to the rigors of materials handling equipment. Fuel consistency is another issue. Under the MACT rules, a biomass fuel can use fuel analysis on a monthly basis for compliance. However, if the consistency of the fuel is highly variable this approach would be counter productive. The conversation then turned to what the owners could do to help the state and local regulators push back on some of these rules. The ISO 15001 program provides standards on documentation. Referenced in that program is the superior energy program, which now has 4 AMSE standards for energy assessments, including steam system assessments. One question the owners had for the suppliers was the level of detail that the suppliers would need in order to get guarantees. Another question is what influences the formation of dioxins. The owners are concerned about start up, shut down, and malfunction, but did not have much discussion.

Norb Wright (Consultant) reported for the suppliers. Start up, shut down, and malfunction is an issue. Most units will experience higher levels of CO and NOx on startup. More details will be needed for the specification because of many of these interactions. Plant operations and control philosophy will also have an impact on emissions. Suppliers will need to know some of these details in order to provide equipment or processes that will attempt to control these emissions. With the low levels of the MACT standards there is the risk of the local permitting agency using that number as the basis for the annual total amount of emissions. One or two unplanned shut downs could cause an excedance of the annual limit. The first time start up of a new unit presents a potential problem as the operating performance of the unit as built, but before tune up, is unknown. Finally, the energy audit issue has some of its own problems, including attention to calibration, level of audit, and calibration. The combination of these factors will make it more difficult to operate units consistently.

Andy Bodnarik (N.H. Dept. of Environmental Services) reported for the regulators. Besides the NAAQS revisions that were given in the morning, there will be additional revisions coming in the next several years. This puts the states under a lot of pressure to come up with plans (SIPs) to come into compliance with these NAAQS. The Tailoring rule helps with regard to GHGs but does not "solve" the problem of an overload of permit requests. The definition of solid waste leads to several inconsistencies. The surrogate issue was discussed. Perhaps total hydrocarbons would be a better surrogate than CO. Besides the emissions rules, there are number of maintenance and material standards that are being issued (fuel tank standards, material standards, etc.). Cost modeling is being evaluated to "help" EPA gauge the cost impact of the many regulations and control methodologies on a national and regional level.

IV. Fundamentals of Mercury Control - Rick Miller, ADA

ADA produces powdered activated carbon (PAC) for the absorption of chemicals. The drivers for mercury control include Industrial Boiler MACT, cement kilns, and Utility Boiler MACT. A typical time schedule starts with base line testing, compliance planning, purchasing, installation, start up, and testing. The compliance date for industrial units is 2013. The utility rules are expected to have a compliance date of 2014. For existing coal fired boilers, the standard is 3 lb/trillion BTU. For new coal fired units, the standard is 2lb/trillion BTU. For new biomass fired units, the standard is 0.2 lb/trillion BTU. This level is getting down to the detection level and may be difficult to measure.

Due to the time overlap, it is anticipated that there will be a competition for resources during the time frame that industrial units must come into compliance. Factors affecting native mercury removal include mercury content, halogen content, and sulfur content. The equipment configuration and type of particulate and sulfur control can also influence the native capture. The carbon injection is typically located after the air preheater. The particle size is in the range of 15 - 25 microns with a surface area of more than 500 m2/g. Systems range in size from a bulk bag system up to utility size steel silo systems. Capital costs range from $150 K - $900 K. The SO3 level in the flue gas competes with the mercury for the sites on the activated carbon. Since the SO3 is in the ppm level and the mercury is in the parts per trillion level, the SO3 can overwhelm the activated carbon. In such cases, alkaline absorbents may also be needed.

Mercury guarantees are tied to measurements from EPA Method 30b or a certified mercury CEMs. Units with fabric filters tend to get better performance as the bag material provides a filter cake that can absorb the mercury continuously. A test program at Cornell University showed that mercury capture with high SO3 was limited to 30 - 50%, while when using trona the removal was from 80 - 95% with considerably less activated carbon. Flue gas temperature is important as higher temperatures require higher levels of carbon injection. In the worst cases, fabric filters may need to replace ESPs. Alternatively, a baghouse can be added after the precipitator. This arrangement is particularly useful for those that sell the flyash. The control logic is based on feedback loops using mercury CEMS. This helps to trim the amount of activated carbon that is injected. There are over 150 commercial utility systems installed in North America. In addition, there have been over 50 demonstration programs.

Sorbent can be delivered in bulk bags, pneumatic trucks, or rail cars. Steel silos can be used. Large silos have a custom fluidizing system designed specifically for PAC. Dilute phase pneumatic conveying is used. Custom engineered distribution manifolds and injection lances are used. A modular approach includes PAC storage, electrical room, feeder room, and blower room. Utility units typically provide for redundancy in the silo system. PAC handles somewhat differently than other additives in terms of its flow characteristics.

More data is needed on biomass firing as well as dioxin and furan capture. Dioxins and furans have been captured in waste to energy plants with activated carbon with high efficiency, but data on coal is scarce. Mercury captured in activated carbon can be disposed of with the fly ash. It doesn’t leach out. However, if the PAC is heated up, the mercury can re-vaporize.

V. Environmental Rules, Regulations, and Implementation Panel - Fred Fendt, The Dow Chemical Company, Moderator

The panel consisted of Jim Eddinger (EPA), Anna Garcia (OTC), Marc Cone (State of Maine), Bob Fraser (AECOM), and John C. deRuyter (E.I. Dupont de Nemours & Company).

Jim Eddinger reported on the Industrial Boiler MACT, Area Source MACT, and the CISWI rules. Public hearings have been held. The comment period ends August 23, 2010. The rules are still scheduled to go into effect Dec. 16th. The MACT covers 13,555 boilers at about 1600 sites. The Area Source MACT covers over 92,000 small boilers. There are proposed limits for 9 of the 11 subcategories on 5 classifications of compounds: PM, mercury, HCl, CO, and dioxins/furans. The proposed rules include an energy management program based on EPA's Energy Star program. Major sources will have to do an energy assessment. Work practice standards apply to Gas1 units (natural gas or refinery gas) and metal processing furnaces. For new units, major source facilities area covered regardless of size. The EPA estimated cost impacts include total capital of $9.5 billion with annualized costs of $2.9 billion. Short term job losses were estimated at 8,000. Longer term estimates ranged from a 6,000 loss of jobs to a 12,000 gain in jobs.

For area sources, there are only 3 subcategories: coal, biomass, and oil. There are no size limits. The proposed CISWI standards are proposing limits for 9 pollutants. Initial and annual compliance testing is required. Continuous monitoring for most of major emissions is required. Over 1000 comments have been received. DOE has indicated interest in working with EPA in regards to the energy related provisions. EPA's Combined Heat and Power Partnership is interested in finding ways in the final rule to promote combined heat and power.

The Transport Rule (CAIR replacement) has "opt in" provisions for industrial boilers. In certain non attainment areas for NOx or ozone, it is anticipated that additional NOx reductions will be needed from the industrial sector to bring these areas into compliance.

Anna Garcia noted that the Ozone Transport Commission was formed under the CAA Amendments of 1990. As a result, SIPs were submitted in the mid 90s for the one hour ozone standard that actually worked. Plans have been proposed to meet the more stringent 84 ppb, 8 hour standard. Consideration is being given to the new proposed standards of 60 - 70 ppb. Despite the states best efforts, some areas are still in non-attainment. There are 3 different types of transport. These include westerly transport (prevailing winds), southerly transport (along the coast night time jet), and the city to city transport (autos, etc.). On bad ozone days, there is a high level reservoir in the upper atmosphere that mixes down into the lower atmosphere at around 10 - 11 am. EPA's modeling indicates that even with a 1.3 million ton NOx cap in 2015, at least 99 counties will be unable to comply with a 70 ppb standard in 2020. Another 40% reduction is needed in the Northeast and a 60% reduction is needed in the mid West. That will likely mean additional requirements on industrial boilers. A 2 phase program is being proposed. Costs ranging from $2000 - 8000/ton are being considered cost effective. For some sectors, higher costs are anticipated. Generally, an average of 50% additional reduction is targeted. Storage tanks, mobile sources, area sources, and other sectors of the economy are being evaluated for reductions.

Marc Cone noted that the plethora of new rules have put some of the states “up in the air”. Issues include the Tailoring Rule, Regional Haze, NAAQS, MACT, and others. The PM2.5 rule is expected to issue in November which will require new SIPs by May, 2011. The new 100 ppb ambient standard has to be dealt with now. Small sources are having difficulty in meeting the standard in the modeling efforts for the new 75 ppb SO2 standard (1 hour basis). Area designations need to be finalized by 2012. Refined dispersion modeling will be done to predict non attainment areas. New SIPs will be required by 2014. The new ozone standard will be issued in August. This will require the new NOx RACT rules as well as new SIPs. The Tailoring Rule impacts major modifications after Jan. 2, 2011 for sources at the 75,000 ton/yr level. July 1, 2011 new GHG sources of 100,000 ton/yr are subject to PSD and Title V requirements. EPA is to undertake rule making in 2011 to meet a July 1, 2012 target for GHG rules. With regard to regional haze, BART impacts require fuel restrictions on sulfur by 2016 and 2018. Maine is reliant on #6 oil. A fuel oil supply study must be completed by 2014. Many states relied on CAIR for Regional Haze reductions. The impacts from the new Transport rules need to be taken into account. Maritime issues are also important for Maine as well as wood burning. Maine has little access to natural gas. LNG has been proposed at a couple of sites, but public pressure has held up or canceled most projects. Engine requirements for diesel and gasoline engines impose fuel restrictions. Recent revisions have made these much more difficult to interpret.

Bob Fraser reported on the major concerns that the consulting companies are being asked to address. These include Boiler MACT, the 1 hour SO2, the 1 hour NOx, and the PM2.5. Companies want to know where they stand relative to MACT. They want to know if they are subject to MACT and, if so, which MACT. Emissions levels and control levels may have been estimated for some of the proposed standards, but things like dioxins and furans have not been measured with any regularity. Results are so site specific that any existing data cannot be relied upon for predictive purposes. Testing will be required to address some of these questions (dioxin level, 30 day rolling CO data, etc.). Several questions arise when a fuel is switched. A new permit is required which may or may not make the unit a “new” unit. The rule is designed to encourage the use of natural gas (Gas1 has no floor limits). However, some units do not have access to natural gas. If the CO limits can be met with combustion controls, then the potential for back end control is there for the other limits. Unit shut downs, as well as plant shut downs, are being considered. Once alternatives have been identified, costs will need to be estimated. The planning horizon is typically longer than the rule changes.

With regard to the 1 hour standards, the “significant impact level” (SIL) is 7.5 micrograms/m3 or 10 micrograms /m3. The SIL figure is the number that triggers the need for an interactive modeling study to determine the impact of a given unit. The EPA has not finalized the SIL figure. Virtually all sources model above the SIL. The “significant impact area” is estimated and 50 km is added to that radius. All sources in the area have to be modeled. This could run into hundreds to thousands of sources. The results will often identify that some of these sources will violate the standard. Then the source to be permitted has to demonstrate that its source does not contribute to the violation. Refined models are now needed. Part of the data need is the NO_2/NO ratio. Thus, several months of computer runs at significant costs are resulting. Results include diesel generators requiring 150 ft stacks. The 1 hour SO_2 does not have a SIL yet. Large sources above the SIL will require interactive modeling. For the PM2.5 standard, the level is very low at 35 micrograms/m3. Background levels are already approaching this level. Proposed SILs are at 1.2 micrograms/m3. Low level sources typically model above the SIL. There are no inventories of PM2.5. Sources that cause modeling problems include coal and ash storage and handling and roadway dust.

John C. deRuyter provided an introduction to industry and its pressures and needs. The internal company pressures include the obligations to serve shareholders, customers, employees, and their communities. All companies have standards for ethics, behavior, etc. Companies provide some kind of goods and services and that involves production requirements. Other pressures include an aging workforce, aging infrastructure, competitive pressures, environmental issues, and international competition.

The US Chemical Industry had $647 billion in shipments. Energy costs represent 10% of shipments. The chemical industry provides 10% of US exports. Direct employment is 803,000 jobs and supplier jobs and expenditure jobs add another 500,000. Efficiency has improved regularly and GHG emissions have been reduced. Production was increasing up until the recession. Employment has been generally decreasing in the last decade. Revenues from new products average 15% per year (products developed in the last 5 years). Capital investment was $20 billion. Replacing equipment represent 30%. Expanding plant for existing product was 22%. New plant was 10%. Efficiency projects represented 9%. Environmental projects represented 10%. Non feed stock energy comes from natural gas (52%), electricity (20%), coal and coke (10%), petroleum (1%), and other (17%). Prices have been volatile, including good grades of coal.

Alternative fuels help to lower costs for both energy and production processes. These fuels also provide lower emissions and less solids and ash handling. Existing solid fuel firing capability is mostly depreciated and difficult to replace. There may be fuel quality limitations either from combustion, operations, or fuel handling. Landfill gas is a good fuel, but with lower heating value and potential contaminants. Off gases and process gases also have limitations. Biomass has transportation and supply limitations. There may also be operational constraints depending upon the type and source of the biomass. Many plant sites are aging. Original facilities have been modified. Infrastructure has to keep up. Space is limited. Retrofit costs tend to be high. Limited capital requires competition with other capital uses on a facility by facility and product by product basis. There is no correlation with the overall chemical sector revenue and expenditure. Integrated facilities can provide lower investment. Out sourcing results from limited capital. This causes problems for rules such as “within the control of the generator”.

Continual and increasing uncertainty makes it extremely difficult to predict required facilities and capital needs. There are also some contradictions in EPA policy. The land fill gas program promoted by EPA encourages the use of landfill gas to minimize methane emissions. However, land fill gas is listed as a Gas2 fuel with a CO limit of 1 ppm. Data from landfill gas boilers indicates an increase over natural gas. If this is the case, land fill gas will not be able to be used. Variability is another issue that has not been adequately considered. Mercury variability has been well documented. However, there are other variations including load, fuel, start up, shut down, malfunction, and other variations. These were not considered in the calculation of the floor limits. There were also detection limit problems. Many of the limits were set using non detect limits for the subject units.

Industrial sources must have assurance of the ability to meet emission limits routinely. These limits must be met with available fuels and controls. The level of the MACT standards are so low that they will be driving plant decisions. Start up, shut down, and malfunction conditions generally have higher emissions. Start up times are limited by the temperature rise of the pressure parts (100 F/hr). During that time, emissions levels (typically CO) tend to be higher. Costs are site specific and the range is wide. The cost per ton for small units tends to be much higher. Costs per ton in the Transport Rule are much lower than for Boiler MACT. EPA estimated the cost of MACT at $9.5 billion. Industry estimates are more like $20 billion.

VI. Particulate and Multi Emissions Control Technologies - Panel, Fred Fendt, The Dow Chemical Company- Moderator

The panel consisted of Jay Shah (Fisher Klosterman), Bob Brown (Kiewit Power), Rajat Ghosh, (Alcoa, Inc.), Jeff Arroyo (SEGA), Ed Campobenedetto (B&W), Brian Higgins (NALCO Mobotec), Kevin Moss (Tri-Mer Corporation), Jay Norman (United Conveyor), John Bowman (Babcock Power), and Heidi Davidson (Solvay Chemicals).

Jay Shah noted that Fisher Klosterman is part of CECO. His topic was wet and dry scrubbers. FKI makes high efficiency cyclones, venturi scrubbers, gas absorbers, dry scrubbers, fabric filters, and ESPs. Absorption involves bringing the gas in contact with a liquid where it is absorbed. Once in the liquid, the compound in question reacts with an additive to permanently capture the compound. Gas absorbers apply to SO2, HCL, H2S, and other gases that dissolve in solvents. Advantages of a gas absorber include low pressure drop, high efficiency, lower capital cost, less maintenance, minimal spare parts, and ease of handling process variability. The important factors are the gas inlet, packing height, type of packing., liquid distributions, mist elimination, and chemistry. Packing ranges from simple shapes to complicated “man made” shapes. The more complicated the shape, the more susceptible to pluggage the packing becomes. Trays can be used rather than scrubbers at the cost of taller towers and more pressure drop. Packed towers can be plagued by plugging from particulates. Distribution of gas and liquid and liquid flooding can be an issue. High gas temperatures can be an issue for plastic packings. A quench section can be added to reduce the gas temperature. Particulate collection ahead of the absorber can reduce the particulate loading. A venturi scrubber can be added in front of the absorber to remove particulates. When used with a chimney tray with mesh pad mist eliminator, the quenched water retains nearly all of the particulates. The use of high efficiency cyclones can also remove particulates.

For dry scrubbers a contact system and fabric filter are required. A unique inductor nozzle injects the dry sorbent into the contactor. Additives include PAC, trona, and sodium carbonate. The operation is totally dry. For the wet scrubber, up to 99.9% HCl and SO2 capture can be achieved. The system is not efficient for mercury and SO3. The reagent ratio is very close to 1:1. The dry scrubber efficiency is limited and the reagent ratio is more like 1:3 or 1:5. The temperature is limited when using PAC. The collection of mercury and SO3 is superior to wet scrubbers.

Bob Brown reported on dryer absorbers. A spray dryer absorber uses a lime slurry of about 20% solids sprayed into a reactor vessel from the top using an atomizer to create very fine droplets. A circulating dry scrubber uses a reactor vessel with an upward flow and a venturi inlet. A flash dryer absorber doesn't have a reactor. The reagent is injected into the ductwork. The dry sorbent injection uses dry sorbent injected in front of a bag house.

Rajat Ghosh noted that Alcoa has smelting operations with low concentrations of SO2 but relatively high gas flows. Alcoa also has boilers. In anticipation of stricter environmental rules, Alcoa has demonstrated an In Duct Scrubbing (IDS) technology. This in duct technology has achieved more than 90% SO2 removal in pilot testing. They are looking to demonstrate this technology in the field. Alcoa will also make a demonstration at an Alcoa smelter in Canada in 2011 A co-current spray is used in the ductwork followed by a mist eliminator. Caustic (NaOH) is used to absorb the SO2. Liquid that is not evaporated is collected for recycle. A regeneration system can be added in which lime is added to the solution, which precipitates CaSO4 and regenerates the caustic. Other additives have been used. The L./G is 15. A patent was issued in 2010. The scrubber is oriented horizontally.

Jeff Arroyo reported on biomass issues and MACT compliance. There are biomass projects that are in progress as they fit into various states renewable energy plans. Closed loop biomass is eligible for renewable consideration, but "open loop" biomass is encountering resistance in terms of its GHG mitigation. Production tax credits of 2.1 cent/kwhr are available for closed loop biomass. There are no tax credits available for open loop biomass at this time, but these are being sought. Biomass includes woody biomass and agricultural biomass. The major benefit is that it can be dispatched and co-fired with coal. It is applicable for smaller plant sizes. There is a debate on the CO2 neutrality relative to GHGs for open loop biomass. The cost and availability of biomass can be an issue. There are still emissions and there is still a stack.

For wall and T-fired boilers, up to 20% biomass can be co-fired with a dedicated delivery system. Cyclone units can tolerate up to 30%. Fluid beds are ideal candidates for biomass, although alkalis can be an issue. Gasification is also a possibility. A new bubbling bed using a woody biomass is being planned for a 66 Mw combined heat and power facility at the University of Missouri. The boiler is being located inside an existing building, replacing an existing boiler. Considerable biomass is available. An offsite fuel handling system is planned so that the site (on a university site) will only have enclosed silos. The BFB will produce 150,000 lb/hr. The plant has its air permit and will finish construction in 2012.

The unit will be considered an existing unit under the Industrial Boiler MACT. The current emissions have to be established for the existing boilers. However, the new BFB will not go into operation until 2012. Kansas City Power & Light is looking at a project using switch grass pellets in a cyclone boiler. A test burn was conducted to establish a baseline with various biomass levels. The coal was a blend of PRB and local bituminous. The unit was a 50 Mw B&W cyclone. Preliminary results indicated that the boiler efficiency dropped as the amount of biomass was increased. As a result the heat rate went up. At the highest levels of biomass feed, the soot blowing went up and the outlet gas temperature went up, leading to a reduction in output. As a result, CO_2 emissions at the plant increased. The CO went up. The PM went down. The HCl went up. Eastern Illinois University decided to eliminate coal completely. An offsite biomass gasification system is proposed with an HRSG to bring steam back to the campus.

Ed Campobenedetto reported on back end technologies for MACT compliance. B&W has built a small boiler simulator at their Barberton, Ohio R&D center. The system has a number of backend clean up systems for testing. For particulates, those units with only a multiclone will need to add an ESP or Baghouse. If a unit has a wet scrubber (for particulates), a wet ESP may be needed or a replacement EPS or baghouse. For units with an ESP, either conditioning or additional equipment will be needed. ESPs can be upgraded at some expense or be converted to a fabric filter. Wet ESPs are being considered for PM2.5 and could be applicable to the MACT rules. For HCl, dry sorbent injection may be applicable. Wet scrubbers should be able to accommodate HCl as they typically collect it anyway.

The ESP could be impacted with dry sorbent injection. If mercury capture is needed, the SO_3 has to be controlled. Depending upon the system, the sorbent(s) might be added before or after the particulate collection system. Mercury capture will likely require PAC injection to meet the MACT standard (3 lb/trillion BTU). Oxidized mercury is soluble is scrubber solutions and can be collected in wet scrubbers. Halogens can be added to the coal to improve the oxidation of the mercury. Another reagent is needed to fix the mercury in the slurry so that the mercury is discharged with the solids. For dioxins and furans, the chlorides in the fuel produce these compounds. PAC is known to capture dioxins and furans, but there is no experience on coal or biomass firing. Another strategy is to go back to the high NOx burners, which reduce CO, THCs, dioxins, and furans, and add back end NOx control.

Heidi Davidson reported on dry sorbent injection tests that were done in Europe. The two sorbents that are used are trona (sodium sesquicarbonate) and sodium bicarbonate (baking soda). Both products are made by Solvay. The testing was to look at 20%, 40%, and 60% SO_2 removal and track the HCl that resulted. At a small utility (400,000 pph), the sodium bicarbonate was tested. The concentrations of SO_2 were about 6 - 10 times the amount of HCl. The additive had to be milled. Three different sizes were tested. (From 2 - 26 microns). The material was injected ahead of an ESP. The SO_2 rate was about 600 lb/hr, the HCL was 60 lb/hr, and the injection rate was up to 2600 lb/hr. Generally high chloride removal can be achieved along with SO_2 removal. Collection ranges were 80 - 90% chloride collection vs 20 - 60% SO_2 removal. With a baghouse, high levels of collection were achieved on both SO_2 and HCl. Temperatures above 275 F are needed to make the trona or baking soda work effectively.

Brian Higgins reported on Mobotec activities relative to Boiler MACT. The EPA preamble indicates that fabric filters plus carbon injection plus wet scrubbers and good combustion practice should be able to meet the standards. Of course SO_2, SO_3 (PM2.5), and NOx also have to be met under most permits. A 56 Mw unit at 80% capacity factor using coal and bark with a Title V permit would not meet the 10 ton/yr CO limit for a major source even though it was in compliance with all of its air permit requirements. For all of these regulations, the details matter.

Getting and understanding the details is a necessity to finding a potential solution to these regulations. For particulates, a baghouse is likely to be a requirement. Combustion improvements will be needed for CO. This includes boiler tuning, mixing, overfire air, etc. needs to be tested. Mobotec uses a boosted overfire air to improve mixing and also help with the NOx. SNCR can be used to bring the NOx back into compliance. Alkaline sorbents can bring about SO_2/SO_3 reductions as well as chloride reductions. If the mercury is oxidized, it can be absorbed in an alkali scrubber. Activated carbon can also be used.

NALCO has water chemistry materials for fixing the mercury in the scrubber solids. For chlorides, a typical 0.1% Cl coal would emit 0.08 lb/MMBTU. The proposed limit is 0.02 lb/MMBTU. With a wet scrubber, the HCl is pretty much captured. With a baghouse and alkaline duct injection, the chlorides are absorbed on the filter cake. Dioxin/furan will be regulated and requires expensive measurements. Activated carbon has been used in MSW plants. However, the coal environment is much different. Combustion improvement will help. Dry sorbents may help. NALCO is trying to develop a proprietary sorbent that would capture mercury, chlorides, and dioxin/furans.

Kevin Moss reported on the UltraTemp Filtration system. This is a dry system that uses a low density ceramic fiber candle system that fits into a baghouse configuration. They can operate up to 900 C. They can achieve removal down to 2 milligram/Nm3 (0.001 grains/dscf). This would translate to less than 0.004 lb/MMBTU. Ceramic filter tubes have been in operation in a number of industries including aluminum powder, catalyst manufacture, wood waste incineration, waste incineration, asphalt reclamation, fluid bed metal cleaning, zirconia production, and munitions incineration (US Army). The product life ranges from 5 to 11 years. The system can use upstream sorbent injection. The surfaces are molded, not machined. The surface is pre-conditioned with an inert powder to create a residual layer. The cake forms on the residual layer. Since the tubes are rigid,

they do not flex with the pulse jet solids removal. A nano catalyst can be embedded on the fibers that form the walls of the tube. With these small sizes, the catalyst is activated at lower temperatures (320 - 350 F). As a result, the filter can act as an SCR. The upper limit would be 750 F. NOx destruction levels of 95% have been achieved. A similar catalyst chemistry can destroy dioxins and furans. Some data exists on clinical waste incineration and building waste incineration. Testing has yet to be done on coal.
The fibrous ceramic tubes are rigid in the baghouse configuration.

Jon Norman reported on trona vs hydrated lime for dry injection systems. The trona can be injected dry. The calcium needs some humidification. The injection locations range from the economizer outlet to the air heater exit. However, below 280 F the activity of the trona starts to drop off. Collection efficiencies for SO2 ranged up to 97% on trona. Sodium bicarbonate is more effective for high efficiency, but more costly. Some NOx reductions have been measured (10 - 20%). An NO2 plume can form with a baghouse and high oxygen levels with SNCR. Mercury removal is primarily by activated carbon. This can be mixed with trona and/or hydrated lime. Oxidizing agents can be used. BPAC with trona tends to get higher mercury capture with less additive due to the reduction in SO3 provided by the trona. Dry sorbents are effective at removing HCl and HF as well as SO3. Hydrated lime is the better choice if SO2 removal is not required as that material captures less SO2. The sodium based systems will capture SO2 as well as the chlorides and SO3. Testing is highly recommended due to the variability of fuels, systems, boilers, configurations, etc.

John Bowman reported on products for mercury, chloride, CO and NOx controls. These include static mixers, activated lignite, circulating dry scrubbers, and regenerative SCRs. Static mixers (Delta Wings(tm)) promote thorough mixing across ducts and flow paths. Physical flow models are used in conjunction with CFD models are used to optimize the location and performance of the mixers. These can be used in front of any device that needs a more uniform, mixed flow into the system.

Activate lignite is a PAC developed by RWE in Germany (HOK activated lignite(tm)). A dry circulating scrubber has been developed for acid gas treatment. The reagent is slaked lime, Ca(OH)2. This is an all dry system. Some water is evaporated into the duct work to provide the humidity for SO2 capture. The recirculation ratio is around 10:1. Units have been in operation in Europe since the mid 90s. There are 21 units on coal and 22 units on waste to energy plants. The largest size unit is 204 Mw. The HCl is removed as well.

The system is comparable in cost to a spray dryer system with lower reagent consumption. A regenerative SCR system was installed at a 54 Mw unit in Burlington, VT. This system is a tail end system that utilizes the flue gas to pick up heat from the ceramic catalyst to reheat the gas, as well as gas burners. The system cycles with some modules heating the flue gas and some modules putting the hot gas over the catalyst. If the gas temperature falls, the gas is switched to a hot bed and the burner brings the bed and the gas back up to temperature. A patent has issued in the US in 2007. There are 4 units in operation. This uses less fuel than straight duct burners to reheat the gas to operating temperature. This system was developed for wood based systems that may have higher alkali concentrations that would be poisonous to the catalyst. Locating the SCR after the clean up system at lower temperature removes most of the alkali. This system can also be used for CO oxidation catalysts.

Charlie Hayes reported on a Membrane Wet ESP as an add on technology to meet Boiler MACT. A wet ESP uses the same principal as a dry ESP to collect particulates. However, in a dry ESP, a rapping system removes the particulates from the collecting plates. In the wet system, water or sprays provide irrigation to move the solids from the collecting electrodes. Southern Environmental uses a membrane to assist in the removal. A polypropylene layer coats the collecting plates in the form of a rectangular box. The discharge electrodes hang from support structure. The gas flows upward through the rectangular tubes.

The membrane provides for uniform wetting via saturation of the membrane material. Sprays are not used. Water drips from the support structure onto the membrane and saturates the material by capillary action. The water drains out the bottom. A pilot unit was installed at a paper plant. After 6 months the membranes were clean and the supports were visible.

A DOE pilot plant was located at the First Energy Bruce Mansfield plant in PA. This was a side by side test of a metal plate and the membrane plate. The results of the tests show that the membrane plate outperformed the metal plate for both PM and SO3 collection efficiency. The reason is that the membrane is wet all of the time, whereas the metal runs dry at some points in time. A commercial system was installed at a paper plant after a sodium scrubber in Alabama. The SO3 concentration was reduced along with the particulates. The unit has been in operation for 5 years. The latest unit is an 8 module system. The filterable particulate collection was 84%. The outlet loading was 0.02 gr/scf (40 milligrams/Nm3).

VII. Boiler MACT Compliance Requirements for Area and Major Resources - Lauren Laabs, Mostardi Platt Environmental

Demonstration of compliance is required for Boiler MACT and Boiler GACT (Area Source). Maximum Available Control Technology applies to major sources. Generally Available Control Technology applies to everyone else. In order to comply, a methodology has to be selected and a demonstration of performance has to occur. Demonstrating emissions includes testing, predicting, monitoring, and calculating (fuel analysis). MACT is presumed to be fabric filters, carbon injection, wet scrubbing, and good combustion practice by EPA. Additional technologies may be required to meet performance. Energy assessments are now required. Units less than10 MMBTU/hr are subject to “work practices” and tune ups. The Initial demonstration will require baseline source testing for each pollutant. Fuel analysis will be required. Testing for dioxin and furan will be required.

Test methods are not necessarily agreed upon and finalized. For ongoing compliance, CEMS are required for CO (over 100 MMBTU/hr) and PM (over 250 MMBTU/hr). The PM CEMS are still an open question, but they will be required. Parametric monitoring will be required for pressure drops, flow rates, temperatures, etc. Calculated emissions require fuel analysis as well as emissions estimates. There is annual retesting required. If everything is unchanged and the last test showed that the emissions were less than 75% of the standard, the testing can be done on a 3 yr basis. Documentation will be critical. The data must be available in the form that is required in the permit. Most permits require some kind of paper document that can be handed to an inspector. The documentation will include the control device parameters, the fuel analysis, the fuel mix, and the test limited parameters. Following the steps isn't enough. The steps have to work. Ultimately a monitor or a test has to verify that the emissions are in compliance. Right now, testing crews are busy. If testing is needed, there is now a lead time to be considered.

VIII. Compliance Testing Methods Contained in NESHAP - Dan Todd, Air Quality Services

Stack testers are busy. Choosing a stack tester is an important step in a compliance strategy. Stack testers need to be qualified. Under the proposed Protocol Gas Verification Program, the "lead" stack tester has to be a "qualified individual". Air Emissions Testing Bodies must be accredited as well. The testing world is evolving. More "exotic" and complicated testing is being required. Detection levels in the parts per trillion level are being required. For all MACT tests, site specific plans are required. For area sources, particulate matter and CO should be routine. Major sources include HCl, which has also been done. For CISWI units several of the elements are also fairly standard.

Some tests are complicated. For mercury, there are a number of methods. Since the levels are approaching zero (ie parts per trillion), there is a lot more QA/QC involved. Dioxins and furans are even more complicated and sensitive. As an example, the method stipulates no smoking during the test and that someone who has smoked cannot touch any of the equipment. Establishing the operating limits is even more complicated. There are seven topics to address in the pre-qualification process.

Open ended questions should be asked to evaluate the stack tester. Topics such as data evaluation, schedule changes, team consistency, professional memberships, shop visits, etc. are all worthwhile. The tester should have a documented safety plan. Subcontractors also must have a safety plan. Checking on how much work is subcontracted, along with references should be done. Experience, legacy, loyalty, etc. are all factors that contribute to selection. Try to get a schedule guarantee in writing. Check on the insurance requirements and normal purchasing practices.

IX. Air Testing Requirements - Dave Ozawa, Platt Environmental Services

Due to the number of different dioxins and furans, there is a problem with detection limits and a longer test period may be required. Particulate matter testing is getting more complicated. Interpretation of what constitutes a particulate (ie stack temperature or ambient temperature) started to include condensables. Some states allowed a subtraction for sulfates. The US EPA tried to get a consistent methodology for PM10. The Method 202 had some problems with artifacts of SO2 forming in the test probes. A nitrogen purge at the end of the run attempts to remove some of these compounds before the final numbers are generated.

X. CAIR Phase II and Industrial Impacts - Rudi Muenster, VIM

Although the new Clean Air Transport Rule (CATR) is aimed at the utility industry, there are potential "opt in" provisions for industry, as well as impacts for cogen plants and qualified facilities. The CATR is intended to address the impact of emissions from one state on another. This requires additional emission reductions over an expanded coverage area. All fossil fuel electric power plants greater than 25 Mw are covered over a 31 state region. The proposed caps are much lower than the CAIR rule. The new SO2 cap will be 71% below the current cap. The NOx SIP Call continues to apply. States cannot arbitrarily include industrial units. The new rule is consistent with the Acid Rain Program and the CAIR rules. Certification, monitoring, and quality assurance according to Part 75 must be in place by the first quarter of 2012. Data must be reported to the EPA Clean Air Markets Division using their electronic data marketing tool.

There are 4 distinct trading programs. There is an annual Nox market for 28 states, an ozone market for 26 states, a group 1 SO2 market for 15 states, and a group 2 market for SO2 in 13 states. New CATR allowances will be allocated in 2012. The NOX CAIR allowances will be severely discounted. The existing SO2 allowances will still be used for the ARP, but not under CATR. All of these states will need new SIPs. Allowance allocation will better match sources and compliance needs. There will be a transition period in 2012 and 2013. Assurance provisions will apply in 2014 when hard state caps will be enforced. A 1-year and 3-year Variability Index had been created. This allowance provides a state with some flexibility in a particular year. The index is calculated as a tonnage limit or a percentage of allocations. If a state budget is exceeded, units emitting beyond their caps will face penalties (even if they have allowances). Each June there will be a notice of finding for annual programs. This will determine which states exceed the cap and who caused the state to miss the cap. Allowances must be in place by year end. EPA is seeking comments on the proposed rule. Comments on including non-EGUs and dropping the size to 15 MW are requested. Owners should determine the applicability of the rule, the supplemental material, the state approach, and provide comments. Be sure to check that your units are not listed as an EGU if they are not.

XI. Energy Efficiency Audits and Tune-ups - Panel, Fred Fendt, The Dow Chemical Company, Moderator

The panel consisted of Fred Fendt (Dow), Mark Garrison (ERM) and Norb Wright (Consultant).

Fred Fendt reported on a path to continual improvements in energy performance. There is a program that DOE has supported called Superior Energy Performance. DOE would like to get this accredited. The system has been approved by ANSI. The goal is to foster a culture of continuous energy improvement. It uses the ISO 500001 approach to provide documentation and certification. The ANSI accredited certification body will conduct 3rd party audits to verify that energy improvements have actually taken place and that ISO 500001 procedures and requirements have been followed. Typical features include having an energy policy, an energy plan, cross management teams, operational controls and procedures, measurement systems, baseline establishment, key performance indicators, energy goals and targets, an energy manual, and a reporting system. A new steering committee called the US Council of Energy Efficient Manufacturers will oversee the program. The DOE will have a Superior Energy Performance administrator. To become fully certified, the ANSI and ISO 3rd party certification procedures must be followed. There will be two other tiers that include registered partner and partner (self certification). The registered partner can mail information to a 3rd party to be reviewed. To date in the two pilot trials no one has opted for the registered party. Registered and Certified Partners can qualify for silver, gold, and platinum levels of performance. The base requirement is a 5, 10, or 15% improvement in energy intensity over a 3 year period. There is also a mature pathway that allows for a 10 year period, but with a high score on a best practices scorecard. All of the systems are not developed yet. The ISO standard is in draft form.

There are 4 ASME system assessment standards. The Measurement & Verification Protocols need to be finalized. The certified practitioners are not in place. The Texas pilot involved 4 plants. They will be going through certification. A second pilot is being carried out. The DOE would like to get at least 2 plants from each state that is participating in the program. One of the commitments is to become a Save Energy Now Leader. This program requires a voluntary pledge to reduce energy intensity by 25% or more in 10 years. The SEP website is www.superiorenergypeformance.net.

Mark Garrison reported on the heightened focus on air quality modeling. In spite of numerous comments in opposition, the new NAAQS standards for NO2 and SO2 have gone final in the federal register. The standards are probabilistic (98th percentile for NO2 and 99th percentile for SO2). The new SO2 1 hour standard is 75 ppb. The form of the standard basically allows 3 exceedances per year on average over 3 years. The new 1 hour NO2 standard is 100 ppb. For NO2, there is the problem of assessing how much of the emissions is NO and how much is NO2. Current procedure is to assume that it is all NO2 and then “refining the model” to allow for lower conversion rates of NO to NO2. For SO2 and NO2, these NAAQS are effective now. New PDS permits and new unit permits must address these standards. Neighboring plants may be drawn into the process when modeling has to account for regional emissions. For criteria pollutants, significant impact levels have to be established. If a modification would result in an impact below the SIL, no modeling is needed. Final SILs have not been established, but proposed levels are sufficiently low, that most units will end up modeling. Analyses are likely to be complex due to uncertainties regarding emissions, terrain, buildings, etc.

Norb Wright reported on energy efficiency. In order to really do an audit, you need to pull together an audit team. Participants should come from the plant, the next plant to be audited, corporate personnel, trainees, and outside consultants. The report format should be established in advance. An up front commitment on funding is required. It is important to understand what level of audit is required/desired. Rules of thumb for key variables (ie cents/Kwhr, $/MMBTU, $/1000 gal, etc.) should be established. During the audit it is important to look for hot spots, hot waste streams, tune ups, performance between similar units, and equipment usage. Confirmation of multi-fuel firing conditions, insulation, economizers, heaters, etc. should be done to see if these are running as designed. Instrument calibration is critical. Proper steam trap selection and operation is an important consideration. Condensate return measurement provides important information about energy use. The lighting is a big source of electrical consumption. Motor driven equipment needs to be checked for unwanted idling. The components of the electric bill need to be checked for demand charge, energy component, and vars. Compressed air is another source of energy usage including pressure requirements, leaks, and "compressed air cooling". Looking at this system on weekends should be checked when systems are supposed to be offline. With 3rd party audits coming, there becomes a question of what and when to do things. High return projects are obvious. Marginal projects need much more documentation to explain why a particular project will not be undertaken (cost, return on investment, permit requirements, etc.).

For boiler tune ups, a written tune-up procedure should be prepared. Emissions limits need to be well understood. Vet your tuner. Insure that there is a "home" for the steam with the boiler at full load for a minimum of 30 minutes. Plant participation, with roles and responsibility, is required. As a guide, it is possible to tune a boiler per fuel per day. Evaluate where to sample the flue gas. The tune up should be run across the firing range. Minimum firing should be done for repeatability and stability. On liquid and solid fuels, the stack should be checked for visible emissions. It is best to do this on a clear day. Combustibles and CO in the flue gas need to be checked so that the combustion process can be evaluated. The flue gas in and out of the economizer and the air heater should be checked. Temperatures and oxygen levels provide important information. For liquid fuel firing, check for proper operation of the atomizing steam, the condition of the tips, and the cleanliness. The system needs to be checked to confirm that all units on liquid fuels if required by the process and allowed by the permit can actually fire the fuel. The tuning results need to confirm that the unit can meet the permitted levels. If not more work is required. Confirm that all of the data has been properly entered into the control system. Move the unit through typical load swings to confirm that the unit will respond. Get all of the information before the tuner leaves the site.

XII. Combustion controls and Performance Optimization - Denis Oravec, Automation Applications Inc, LLC Moderator

The panel consisted of David Farthing (Federal Corporation) and Chris Henderson (AAI).

Denis Oravec pointed out that process controls can help the combustion system stay within the limits necessary to meet the emissions limits. These controls impact the process every day.

David Farthing reported on combustion controls for NOx control. The combustion reaction is the oxidation of fuel for the generation of heat (and light) along with some combustion byproducts. These products include CO2, CO, NOx, nitrous oxides, and sometimes particulates and other compounds. During combustion, the nitrogen and the oxygen in the excess air can react to form NOx. This process is temperature dependent. Flue gas recirculation can help reduce the temperature of the gas to reduce the production of NOx, particularly for gas fired units.. In one case, the conventional burner was designed for 15% excess air and 62 ppm NOx. The new permit was 42 ppm. The design target was less than 30 ppm. The as found condition was at 2% O2 and 68 ppm NOx. For gas recirculation, the furnace has to be able to handle the gas volume. Gas recirculation piping was added along with an increased fan size. A cross limited metering system with oxygen trim and active NOx control was set up. Air flow control provides signals to the fan damper, fan drive, and the gas recirculation damper. The measured NOx and O2 is input to a calculator to convert the measurement to the corrected 3% O2 level. This is compared to the NOx set point. This sends a signal to the flue gas damper control. An oxygen trim can also be used. At full load, the NOx was below 30 pppm and the O2 was 3%. At low loads the NOx level tends to rise as the excess air level tends to increase. With flue gas recirculation, the overall efficiency tends to decrease. As the flame temperature is reduced, the CO level will tend to increase. For a 40 kpph boiler, the project cost was $68 K. The flame front has to be stable enough to handle the gas recirculation flow. The air fan also has to have enough capacity to handle the re-circulated flue gases.

Chris Henderson reported on control techniques for controlling emissions. Higher excess air levels result in increased NOx levels. Lower excess air reduces NOx and improves efficiency, but increases CO. Staged combustion attempts to reduce the oxygen level at the point where NOx is formed and then adding air to burn out the fuel (and CO) before the gas gets too cold. Flue gas recirculation can control temperature somewhat independently. With stokers, the gas recirculation cannot always penetrate the furnace over the flame. In this case, the over fire air and the gas recirculation can be combined to get enough mass flow to penetrate the furnace over the stoker grate. All advanced control schemes must be built on a solid foundation of clean, repeatable, variable signals. Appropriate sensing elements must be used for the application at hand. Instrumentation must be calibrated accurately. Flow measurements should be compensated for temperature and pressure. With good controls, low excess air firing can be attained. The optimum fuel/air ratio for a given boiler usually changes over the load range.

Historically, characterization curves have been utilized to provide an air demand signal for different loads. Load tests are used to measure the air flow required. Stoichiometric calculations can provide the theoretical amount (stoichiometric amount) of air required. Since the boiler load is proportional to the fuel flow, the boiler master signal can be used for these calculations. Combustion constants can then be applied to determine the air flow that is needed. Gas or fuel oil flows are generally fairly easy to measure. Solid fuel flows are much more difficult to measure. Even gravimetric feeders have inaccuracies, especially drift. Substitute measurements are often used to infer fuel flow. Steam flow can be used at steady state. However, during load swings, the steam flow is ahead of the fuel on increases and behind the fuel on decreases. Models can be made for these transients. However, consumed air is a more "real time" measurement. The total quantity of combustion air is determined on a mass flow basis. Tramp air can be accounted for by measuring leakage over different air flow rates. Oxygen trim can be used. CO trim can be used (and provide an indicator of problems with the unit).

Trimming multiple levels of air is a challenge. Constant ratio is the theoretical answer, but certain systems are sensitive to primary air. Stoker air flow acts like a gas pedal. Increasing the air consumes more stored fuel on the grate. FGR mixing with combustion air is another challenge. Pitot tubes can be used provided some kind of automatic cleaning system is used. Overfire air flow is often controlled by pressure. However, at lower loads, less overfire air is needed. A staged approach to overfire air may be a better solution as load is increased.

XIII. NOx Emission Control Technology - Panel

The panel consisted of Bill Gurski (Hamworthy Peabody Combustion), Blake Stapper (URS), Bob Morrow (Detroit Stoker Company), Joe Rios (Peerless Mfg Co.), Joe Comparato (Fuel Tech Inc.), and Ed Schindler (CCA).

Bill Gurski reported on burners for low NOx firing. Safe and stable operation is paramount for all burners. Bill presented the curves for CO, NOx, and boiler efficiency. As excess air increases the CO is reduced. However, the NOx increases and the boiler efficiency decreases. When the boiler efficiency decreases, the amount of fuel needed increases which increases the emissions of GHGs. The challenge with efficient combustion is to know the application in terms of boiler design, burners, fuels, and operations. Best practice is based on the individual boiler or facility.

For oil firing, modeling, air balancing, the firing chamber, the atomization, the tip selection, the emissions, the constituents, the fuel, and the equipment conditions are all important for selecting the burner and control system needed to meet the performance requirements. Over 90% of the flow going through the burner is air. If the air is out of balance, there could be performance issues. Balance within the burner and between burners is important to overall burner and boiler performance. Air distribution within the burner of +/- 5% is desirable as well as +/-2% from burner to burner. The same applies to FGR. With solid fuels, there is the potential for erosion with flow unbalance. The erosion rate is exponential with velocity.

For oil firing, the tip selection is critical. Fuel preheat is required for heavy fuels. Tip designs can be internal mix, external mix, hybrid, and mechanical. The internal mix uses a large amount of atomizing steam (0.2 - 0.3 lb steam/lb oil). It provides excellent atomization quality. The increased steam use can also reduce NOx. The external tip requires much less steam (0.03 - 0.05 lb/lb fuel). Atomization quality is reduced. For light oils, this is not usually a problem. As the mixing is external, the steam pressure does not have to be higher than the oil pressure.

Blake Stapper reported on CO concerns for low NOx burners. Good combustion technology is part of MACT. The MACT boiler doesn't really exist (the one that meets all 5 limits simultaneously). The proposed emission limitations are not linked to the use of any particular control technology. The limits are based upon the cleanest fuel in any subcategory. The limits have to be met at all times. While CO is used as a surrogate for total organic compounds, there was not data taken on total organics. At high CO levels, CO and total organics move together. However, below 100 ppm CO, there is no additional benefit to organics. Variability was only considered for the best units. These units are most likely to be the ones that have the least variability. There was virtually no testing done on equipment with low NOx burners. NOx regulations are getting tighter as the NAAQS levels are dropped. Typical guarantees are for loads above 25% in the range of 100 - 400 ppm. Tuning for low CO and addressing NO in the back end with SCR or SNCR can work at full load, but most of these systems require higher temperatures which are not available at start up or low loads.

Bob Morrow reported on NOx Controls for spreader stokers. For spreader stokers, the fines tend to burn in suspension, while the coarse fuel burns on the grate. Test data from a unit with no NOx control showed the NOx increased with excess air. The CO did not increase markedly until the oxygen dropped below 2%. Above 6% oxygen, the NOx was slightly higher. This was all done at full load. The level was 50 ppm. The SNCR system can provide a reasonable amount of NOx reduction. Gas reburn can be used to reduce NOx as well. The NOx level at one stoker facility was reduced from nearly 500 ppm down to 220 ppm. A new unit that went into operation in Virginia at 80,000 lb/hr with a full load natural gas burner. The NOx limit was 0.35 lb/MMBTU. The CO limit was 0.18 lb/MMBTU. This unit was part of the EPA ICR testing. The unit has an SDA and baghouse. The gas temperature was 180 F. The CO on coal was 44 ppm. However, the unit would not make the new unit level of 9 ppm. The unit also did not make the HCl or the dioxin/furan limits in MACT. The biomass units tend to be higher in moisture. This causes considerable variability in CO. In the northeast, there have been SCR installations on biomass units that have been operating for a few years. There are a few with CO catalysts as well.

Joe Rios reported on SCR systems on mixed fuel systems. Applications include incinerators, hazardous waste units, oil/gas mixtures, syn gas, process off gases, refinery fuel mixtures, and multiple stream firing. With mixed fuels it is often difficult to predict the level of NOx. Further there could be contaminants that eventually poison the catalyst. With mixed fuels that are variable in NOx production, it is possible to over inject the ammonia when NOx production is low. Feed forward control systems can be based on calculated and empirical values. A CEMS system can provide feedback control. Ammonia slip can provide an integral signal. However, there is little room for error (often 5 ppm). Catalyst deactivation can be caused by alkalis, phosphorus, vanadium, chromium, arsenic, siloxanes, and fouling. In one retrofit application, the NOx was to be reduced on an incinerator firing a mixture of 4 fuel streams. The ammonia slip limit was 5 ppm. Catalyst life was to be 17,000 hours. NOx had to be reduced by 95% from 250 ppm. There was on CEMS. The particulate loading was 34 milligram/Nm3 dry. The unit featured inlet and outlet NOx analyzers to handle big swings in NOx production. A flue gas flow meter was included. Soot blowers were used for particulate management.

Joe Comparato reported on layering the various technologies for NOx control. Combustion tuning, combustion controls, and post combustion controls can be used together to minimize the overall cost of the level of control that is needed. Even for units that have required SCRs, the better that combustion controls can do, the lower the cost of the SCR. Ideally, in the combustion zone, substoichiometric conditions exist where the nitrogen in the fuel is being released. This reduces the NOx that was produced. The CO and unburned carbon needs to be burned out. The over fire air provides the required air for burnout. SNCR then can reduce the NOx that was formed by reaction with ammonia, or ammonia producing compounds. In incinerators and chemical recovery boilers, there is a long residence time that allows the removal to reach high levels (80 - 90%). Power boilers that run hot can be as low as 20%. Boilers designed for low NOx burners can get up to 70%. An SCR catalyst reacts NH3 and NO at 600 - 700 F. With less NOx being produced, less catalyst is needed and less ammonia is needed. Static mixers can assure that the NOx and the ammonia is more uniformly mixed. This tends to reduce the level of ammonia slip, which serves as a limit on the catalyst. The goal is to then optimize the levels of conversion in each of these systems in order to minimize the overall cost to reach a given level of overall NOx reduction.

Ed Schindler reported on combustion solutions for low NOx operation. In PC firing, air and fuel balancing, burner modifications, overfire air, SNCR, and SCR can all be used. Boosted overfire air can provide significant CO reductions. CFD modeling is used to optimize the air flows and any injection flows. The goals on air and fuel balancing are 5% on air and 10% on coal. Optimized combustion can provide as much as a 50% reduction in NOx levels. For burners, the internal recirculation zone needs to be controlled to maximize the coal residence time in that zone. The components need to be positioned correctly. Using these techniques on a new low NOx burner can achieve 0.35 lb/MMBTU NOx. Tangentially fired units require a different approach. The bluff body portion of the coal nozzle can be modified to get more devolatilization closer to the burner. This change can get up to a 25% NOx reduction. For effective overfire air, mixing must be complete in order to minimize the CO and unburned carbon. CFD modeling helps to optimize the mixing. For SNCR systems, tilting injectors can assist in following the temperature changes that come from load changes. CFD is also used to help design the system to attain appropriate penetration of the injection.

XIV. Fundamentals of Working with State Regulators - Ann McIver, Citizens Thermal and Don van der Vaart, NC DENR Air Quality Division

Ann McIver is a former state regulator, pointing out that all stakeholders have a point of view that must be heard and respected. Perception is reality. "Industry" is just out to make a profit. "Regulators" just don't understand. These biases don't make for a good working relationship. The tools for working together are knowledge, experience, and resources. Everyone in the discussion has responsibilities and authorities. It is important to appreciate the limits of authority. Respect that an agreement to disagree is an agreement. Relationships are important. Be responsive when called. Plant tours, site visits, and training opportunities are very helpful in getting the parties on the same page. Organizations do experience turnover. There is a need for periodic renewal in these areas. Transition management is just as important. Make sure the agency knows if there is a change in personnel to contact. Request a meeting to discuss complex issues. Be open about the challenges you're facing. Be patient with new staff assigned to an old project.

Don van der Vaart pointed out that the state relationship with the EPA is the foundation of the state position. Understanding that relationship helps to provide the understanding of the states actions. The facility has to put into action whatever rules and agreements are made. EPA is an enormous agency. There are many different groups or departments with different agendas. While the states were intended to implement the Clean Air Act and the Agency was intended to be a technical resource, the decision making tends to defer to the Agency. When a facility calls the EPA, the person answering the phone may give an answer over the phone, but no documentation is likely to be forthcoming. A follow up call may be made, but a different person is likely to answer.

The proposed Boiler MACT is essentially an assault on solid fuel firing, especially for smaller units (less than 150 MMBTU/hr). At the national level, the trade associations can generally hold their own against the national environmental NGOs. However, at the state level, the trade associations don't generally participate (being national organizations). The NGOs get reimbursed for attorney's fees from EPA if they win (loser pays). Corporate offices don't want to get into law suits, especially environmental ones. They prefer to settle law suits. As a result, at the state level it is not likely that a particular interpretation of a rule gets challenged. The permit process doesn't start in a company until the project is approved. Knowing this the state agencies are in the driver's seat. The facility needs the permit and needs to spend the money on the project during the budget period. The MACT rule will tend to force industrials to natural gas. The GHG rules will tend to force utilities to natural gas. The new NAAQS standards will make it difficult for anybody else to use solid fuels. The GHG rules are being rushed at a rate that is faster than any other program in the history of EPA. The EPA is asking the states attorneys' general offices to state by January 1 that they cannot meet the requirement for SIPs. This will in turn allow EPA to create a FIP for GHG compliance. The state of Texas has responded negatively.