Environmental, Energy & Technical Committee Meetings

March 8-9, 2011
Radisson Hotel, Reagan National Airport
Arlington, VA
(703) 920-8600

TUES-WED MARCH 8-9, 2011

FOCUS GROUP SESSION – Natural Gas Supply & Availability

Focus Group Moderator – **Ann McIver**, Citizens Thermal

Supply Availability and Use of Natural Gas

Theresa Pugh of the American Public Power Association reported on the supply availability and use of natural gas. The APPA has done a study on the implications of greater reliance on natural gas for electric generation and manufacturing customers. Their report is available on their web site.

The APPA represents over 2000 state and municipal utilities that operate as "not for profit" organizations. Challenges for a large switch to natural gas for electric generation include increased supply and demand requirements, increased infrastructure requirements (pipelines and storage), operational challenges, retrofitting and replacement, and investment requirements. The APPA hired ASPEN Environmental in California. The impact on electric prices will be determined by the Regional Transmission Organizations, which use a single clearing price mechanism to clear the market. The large increases in regulations that are in play over the next 5 years are causing many coal fired plants to consider switching to gas.

Historically, US demand for natural gas has never been higher than 23 TCF. The study looked at several demand forecasts including that done by INGAA. If 335 GW of coal firing were all converted to natural gas, an additional 14 TCF would be needed. It is interesting to note that there were gas curtailments in some of the Southern states during the past two weeks. While there are large deposits of shale gas in the US, there are questions about the ability to provide the supply at the right time and the right price. Shale gas requires the use of hydraulic fracturing which uses a lot of water. Concerns include contamination if the fraccing liquids migrate, seismic activity, and claims that emissions might be higher (methane).

Underground gas storage costs include depleted oil/gas facilities and salt storage facilities. The salt storage facilities can provide high deliverability, meaning that gas can be injected quickly and withdrawn quickly. Oil/gas storage facilities tend to be slow in this respect. There is not enough storage in the pipeline system to store the gas for reliable operation at the utility.

The proved reserves today for gas are at about the same level as they were in 1975. The average production per well has continued to decline. Prices that are quoted are in the range of $5-7/ MMBTU at the wellhead. Generally, shale gas is not profitable without a $9 price level. Currently, natural gas liquids production and various tax incentives (and other subsidies) are allowing shale gas to be produced at the current low prices. From 1990 to 2008, the pipeline industry added 45 bcf/day of capacity. The needed capacity for coal switching would be 70 bcf/day. Twenty one states would need more gas pipeline capacity into the state (not counting getting the gas to the cities within the state). In 16 of those states, the increased demand would exceed the total current gas burn. In many states, peak monthly demand would be exceeded (and certainly peak day demand). Not every state has gas storage that is within easy reach of the power plants and very few have high deliverability.

Pipeline availability and storage availability are not equal to the requirements of an electric power plant. These plants need high deliverability to manage load swings and peak load demands. Operational challenges include curtailment issues, balancing rules, and contingency planning. Utility gas load is not flat. Nuclear and coal tend to be base loaded. Natural gas takes the load swings. Gas fired replacement will typically mean replacement. There are still permitting issues for natural gas including NOx levels, CO2, and modeling. The new primary NOx hourly standard of 100 ppb will require dispersion modeling in attainment areas. Shorter stacks at gas turbine facilities have led to modeling issues in permit applications.

The estimated cost to do all of this was $750 billion, not including increased commodity costs or local costs in increase distribution capability. Curtailment requirements need to be revisited in order to assure reliability of electric supply. This will mean that electric generation would likely have higher priority for gas supply than manufacturing plants. If CO2 capture and storage becomes a requirement, there would be a need to create a pipeline system (roughly 3 times the size of the current gas pipeline system) for CO2 as the storage locations do not necessarily match up with the generation stations. The legal requirements for getting a permit to inject the CO2 (underground injection well) are laborious and time consuming. Once obtained, the water permit must be renewed every 5 years.

Natural Gas Supply Outlook

Philip Budzik of the US Energy Information Administration reported on the Annual Energy Outlook and the natural gas supply projections. The EIA does not talk in terms of forecasts. Rather they make a set of projections. The reference case gives their best projection given their current understanding. Changes in regulation or law are not anticipated in any projections. A number of scenarios are run (in the neighborhood of 30).

The 2011 outlook includes projections of shale gas supply. It is important to point out that production from a well is only known after the well has been drilled, logged, and started production. Currently consumption is expected to grow at a relatively slow rate. Domestic supply has been increasing. In 2009, imports from Canada made up 11% of supply. With the increase in supply from shale gas, imports are expected to decline to about 1% over the next 35 years. The projections do not anticipate any CO2 requirements. The shale gas fraction would go from 14% in 2009 to 45% in the future. Total gas demand would increase to 27 TCF. The shale gas projections have increased as the production from shale gas has increased. Price projections have been lowered, but are still in the range of $5-7/MMBTU for the wellhead price at Henry Hub (used as the base on the NYMEX market).

Shale wells tend to have high initial production rates, but drop tend to drop off rapidly. None the less, the resource estimate has been increased to 2552 TCF. The number of fields being developed has increased. All of these formations are heterogeneous. That means the production and quality are variable throughout the field. There are more variables associated with shale formations. These include depth, thickness, pore pressure, carbon content, pore space, carbon maturation, gas-oil-water content, and clay content. For example, the higher the clay content, the more difficult it is to fracture the rock. This leads to higher cost. In a shale formation, the gas is stored in the pores and the gas that is stored in the carbon. The gas in the pores comes out quickly. The gas that is stored in the carbon provides the long term potential for gas production.

Since this industry is relatively new, the projections for the gas stored in the carbon and its future production are limited. Initial shale gas well production can vary by as much as a factor of 10 across the formation. Adjacent gas well productivity can vary by as much as a factor of 3. A "typical" well costs about $10 million to drill and complete. Due to the variability in gas production, one out of 5 wells is likely to be a loss.

In traditional oil and gas regions of the country, regulations are in place for production wells and injection wells. In other regions without an extractive industry, there are a lot of confusions (New York for example). Producers tend to maximize rates of return (not necessarily rates of resource recovery). As the long term production rates are relatively unknown, it is somewhat speculative to project the level of reserves. Re-completion and re-fracturing has not really been done yet. As the major oil companies move into this production, the amount of publicly available data will decrease.

How EIA Sees the Future of Industrial Energy Consumption

Elizabeth Sendich of the US Energy Information Administration reported on the demand side projections from the EIA -- in particular, the industrial energy consumption projection done by the industrial demand subgroup at EIA. The EIA produces an annual projection (the AEO) and a manufacturing consumption study (MECS). The demand side includes the energy outlook, production by industry, consumption by area of use, boiler consumption by fuel, and cogeneration consumption by fuel. The annual outlook generally assumes current laws and regulations. Steam demand and byproducts from process and assembly and building areas are passed to the boiler and cogeneration area. Boiler fuel shares for steam only applications include some fuel switching based on fuel prices. Cogeneration fuel shares are fixed. Byproduct fuels are based on cost of recovery.

The MECS comes out about every 4 years (partly to handle confidential business information). Industrial fuels include oil, gas, coal, renewables, and purchased electricity. Renewables include biomass, hydro, MSW, and possibly land fill gas. After a forecast pickup to 2015 (economic recovery), the curves appear to be relatively flat into the future. There is a combination of energy efficiency and market forces that are at work in the forecast (done by IHS Global Insights). The major industry consumers are primary metals, stone/clay/glass, chemicals, paper, food, non-manufacturing, durables, and other. Refining was not included in this particular study, but is included in the overall work.

The EIA website has all of this information and can be used somewhat interactively to generate user specific graphs and charts. Utilities are done separately with their own system models. The NAICS codes provide the industry segmentation. The current study was based on $2005 dollars. The most recent forecast was done in October. The EIA does not advocate any particular scenario. The boilers and cogeneration component of energy use covers roughly 1/3 of the industrial energy use.

The expectation is that cogeneration will expand in the coming years. This result is primarily due to the estimated relative prices of natural gas and electricity. Natural gas prices are currently expected to remain somewhat steady while electricity prices are expected to rise. The model is at a regional level to account for different price levels in the various regions. As a result the share of natural gas will increase. The use of oil, pet coke, and LPGs is expected to decrease. Coal would also experience is a slight decrease. Biomass shows a slight increase in share. Production increases drive growth in boilers and cogeneration. In the shorter term, the growth will be in heavy industries. In the longer term, the growth comes in "light" industries. The EIA home page is www.eia.gov.

ENERGY COMMITTEE SESSION

Frederick P. Fendt, The Dow Chemical Company, *Energy Committee Chairman*
Robin Mills Ridgway, Purdue University*, Energy Committee Vice-Chairman*

Fred Fendt of The Dow Chemical Company gave the anti-trust admonition. **Bob Corbin**, CIBO Member Services Consultant, introduced the new members and guests. Bob noted that we have 10 new members this year, with total membership up to 121 companies. The usual "round the table" introductions were done. Fred pointed out that over the last 10 years there have been a number of presentations on steam best practices and energy performance at the DOE. A panel has been assembled including Scott Hutchins at DOE and Craig Cheney of Project Performance Corp.

Scott Hutchins is with the Industrial Technologies Program at DOE under the Energy Efficiency and Renewable Energy division. There are 3 primary groups – Technology R&D, Partnership Development and Deployment, and Energy Services. Nearly 70% of the budget is for R&D. The program has produced over 220 products and services for industry which has resulted in 9.3 quads of energy savings. With the new emphasis on energy efficiency, the division has gotten a proposed budget increase in the FY2012 budget. The goal is to inspire US companies to embrace a corporate culture that values good energy management.

The Save Energy Now LEADER program involves a pledge to adopt a coal to reduce energy intensity 25% or more over a 10 year period. The program requires the assignment of an energy manager, the development of an energy intensity baseline, and the development and execution of an energy management plan. The companies then take steps to improve energy efficiency and report the results. In addition to the plant level activities, supply chain management is also to be promoted. The Superior Energy Performance program is being formalized this year. The draft ISO 50001 standard has been issued. There are tools available for basic and advanced principles. One of the developments for this year will be to put these all into one master program.

The DOE has 26 University based Assessment Centers that can provide a one day assessment at a site for free. There is also a State Energy Efficiency (SEE) Action Network. This is a partnership with the states to drive energy saving practices to the state and local levels. The Save Energy Now ALLY program includes universities, utilities, trade associations, and other groups. This group aims to promote energy savings practices across industry.

Fred Fendt of The Dow Chemical Company reported on the energy program at Dow. Energy efficiency is important in both Dow products and Dow manufacturing processes. Dow is a charter member of Save Energy Now as well as the ISO 50001. There are two kinds of sites: those with energy conversion and those without energy conversion. Since 1990, there has been an improvement in energy intensity of 38%. Since 1994, about 1.7 quads of energy consumption have been reduced.

Craig Cheney of Project Performance Corporation reported on the Superior Energy Performance program. This program is intended to drive implementation of continuous energy saving practices. The program provides a roadmap for achieving continual improvements in energy performance. The program is ANSI accredited. The program will be launched nationwide in 2011. The program will use the ISO 50001 standard as a foundational tool for energy management. A tiered program will establish and entry point for companies at all level of experience. A record of performance improvements is created. The first part of certification requirements is conformance to the ISO standards. The second part is the actual measured performance improvement.

ISO 50001 imposes requirements for measurement, documentation, reporting, design and procurement practices, and process control. The components of an energy management standard include an energy policy, an energy plan, base line establishment, measurements, reporting, auditing, and an energy manual. The tiered performance includes silver, gold, and platinum performance standards. The program distinguishes between newly established programs and mature programs (those already having programs like Dow). There are resources that can be provided by DOE, including training programs, tools, and assessments. With increasing rigor, it is hoped that value would be recognized in the program to aid in insurance, banking, CO2 credits, etc. There about 2 dozen companies that are participants in the program. Dow went through their test certification last week.

Fred pointed out that Dow uses a fair amount of oil and gas as feed stock for its products. The SEP Certification aligns well with Dow's corporate commitment to sustainability, energy efficiency, and climate change. The first site has gotten a certification. Fred is currently working with 3 more sites. From a certification point of view, the ISO 50001 process builds on other ISO standards so that the actual additional work load for energy amounts to only about 10% incremental. One of the points to be made to management is that the cost savings from saving energy generally go straight to the bottom line. The corresponding requirement for sales increases to gain the same increase in profits is often very substantial.

A case study at Dow looked at insulation in particular. Fred noted that insulation and steam traps are two big energy opportunities. The Freeport facility is about 30 years old that is very energy intensive. Good management practices are in place at the plant. Never the less, a 2 day assessment was done to evaluate the potential for energy savings for insulation alone. The net result was an estimated potential of 11 billion BTU/yr savings. The payback was less than 3 months. The facility had previously done a steam system assessment that identified insulation as an area of improvement.

ENVIRONMENTAL COMMITTEE SESSION

Maxine D. Dewbury, The Procter & Gamble Company, *Environmental Committee Chairman*
Robert (Rob) Kaufmann, Koch Companies Public Sector, LLC, *Environmental Committee, Vice-Chairman*

Maxine D. Dewbury of The Procter & Gamble Company noted that the bulk of the afternoon would be devoted to the Boiler MACT slate of rules. The minutes from the last meeting were approved as written. The litigation update will start tomorrow.

Boiler MACT Slate of Rules – John C. deRuyter, E.I. DuPont de Nemours & Co.

Major Source MACT -- John pointed out that there are 4 rules that were issued at the end of February. These include the Industrial Boiler MACT rule, the Area Source MACT rule, the CISWI MACT rule, and the definition of solid waste. The EPA has stated that they will reconsider the rule immediately for certain issues. Others can request reconsideration for their own specific issues on the rule. On the plus side, the EPA kept the work practices rules for Gas 1 (ie natural gas). For Gas 2, the EPA stated that if the composition is similar to Gas 1, it can be treated as Gas 1. For start-up and shut down, the manufacturers recommended procedure will become the standard.

In some cases, the standards are still too low or were revised even lower. For dioxin/furans, there was no real change in the standard, but there was a change in the test requirement. The affirmative defense provisions were adopted for malfunction. This requires the operator to document all the things that were done to minimize emissions during the malfunction. Small units are defined to be less than 10 MMBTU/hr. A limited used definition based on hours of operation (876 hours) was added. Health based emissions limits were not included in the final rule. Emissions averaging would be allowed for all solid fuel boilers at a facility. This could be helpful for mercury, chlorides, and particulate matter.

Stack testing must be done for compliance. PM CEMs are still required for coal, biomass, and residual oil boilers greater than 250 MMBTU/hr. Parameters during a performance test become operating limits. Pro-rating will be allowed for heat input (ie for sorbent injection). Oxygen monitoring will be required and the lowest hourly average oxygen during testing must be maintained on a 12 hour block average. The problem is that the testing refers to stack gas. Most O2 analyzers are at the economizer outlet. Further, the analyzer has to comply with other requirements. This issue may be one that EPA thought they were making a concession, but the details have obviated the benefit.

Fuel analysis can be used to meet mercury or chloride requirements. A monthly coal analysis would be required. Each new fuel or new supplier of fuel would require a new test. On a malfunction, notification is required in 2 days, reporting is required within 45 days, and the incident has to meet the definition of a malfunction. The affirmative defense can be used for financial penalty, but not for injunctive penalty.

An existing boiler or process heater at a major source facility must have a one tie energy assessment performed on the facility by a qualified energy assessor. Energy assessments must include visual inspections, evaluation of the operating characteristics, O&M procedures, inventory of major energy consuming systems, review of A/E plans, review of energy management practices, list of major energy conservation measures, list of energy savings potential of energy conservation measured, and a comprehensive report detailing ways to improve efficiency, cost of improvements, benefits and time frame for recouping investments. "Energy Use Systems" is defined to include (but not limited to) process heating, compressed air, machine drive, process cooling, facility HVAC, hot water, buildings, and lighting. The scope and time required for assessments are broken down as facilities using less than 0.3 trillion BTU/yr, those using 0.3 - 1.0 trillion BTY/yr, and greater than 1 trillion BTU/yr. The word "maximum" time to be spent on these assessments was used. It was not clear if that was intended to be the expected "maximum" time or the "required" maximum time.

The EPA dropped the requirement for a facility energy management program according to Energy Star. The qualified energy assessor definition does not require a third party assessor. Cost effective energy measures are deemed to be those with a 2 year payback or better. The final rule includes an alternative output based emission limits that allows the use of emission credits earned from the implementation of energy conservation measures. This sounds like a mini GHG program which could be illegal (ie having no Congressional basis).

On dioxin/furans, EPA did not change the standard. There is no emission averaging provision for dioxin/furans. The total select metal option (TSM) was not included. EPA indicated that they were not interested. The HAP is metals, not particulates. The ICR asked for 10 metals, instead of 8 in the original rule. The definition of hot water heaters was not changed. A tune up will be required every two years.

For the Area Source rule, there is a table available on the limits. There were some modifications Most of the emission limits were increased. Oil and biomass have tune up requirements with no emission limits. There is no emissions-averaging on GACT. There was also no relief on the testing requirements.

For the definition of solid waste, the flow chart in the proposed rule was modified only slightly. The first test is whether or not the material is a traditional fuel. Alternative fuels are now considered to be traditional fuels (includes currently mined coal residues and clean biomass). These must not have been discarded. The next test is whether or not the material has been discarded. If so, it would normally be a waste. The waste material can be processed to meet the requirements of a fuel. These materials have to meet the legitimacy criteria for fuels.

The legitimacy criteria include whether the material is managed as a valuable technology, the material has a meaningful heating value, and the material does not contain contaminants at levels comparable to traditional fuels the unit was designed to burn. Scrap tires and resonated wood do not have to be managed within the control of the generator, but still have to meet the legitimacy criteria. EPA did not establish a value for "meaningful" heating value. Since traditional fuels have been so closely defined, it will be very difficult to get a waste material declared a fuel. If the material is a waste, then units that burn any waste material become an incinerator and will be regulated under the incinerator rules.

For the incinerator rules (CISWI), there were several changes to the rule that actually were improvements. Burn off ovens, soil treatment units, cyclonic burn barrels, lab analysis units, and space heaters were specifically exempted from this rule. The definition of small, remote incinerators was revised. There are no opacity requirements. The monitoring requirements were revised. There is still a PM CEMs requirement. The calibration frequency requirements were relaxed. No emission averaging was included. There is no separate treatment of start-up and shut down. A unit will remain under CISWI for 6 months after waste is no longer combusted.

It was suggested that a number of people provide draft comments on the above issues for preparation of the overall comments that will go back to the agency as part of the reconsideration process. Comments, issues and suggestions from any member are encouraged.

Reconsideration – Lisa Jaeger, Bracewell & Giuliani L.L.P., reviewed some of the legal issues surrounding reconsideration. Reconsideration issues that EPA will consider include revisions to the proposed subcategories, fuel specification for gaseous fuels, work practice standards for limited use boilers, limitations on fuel switching for CISWI, and affirmative defense for malfunction for Area Source boilers and CISWI units. Additional issues include monitoring requirements for CO, revisions to the proposed dioxin emission limits, PM standards for GACT, and Title V applicability.

Administrative reconsideration requires that the issue could not have been commented on and be of central relevance to the outcome of the rule. EPA can grant or deny reconsideration of an issue. If granted, EPA puts a Federal Register Notice of Reconsideration which will be followed by a Notice and Comment period and a Federal Register publication of final Reconsideration of Petitions.

The EPA reconsideration will be only on the 3 MACT rules and not the definition of solid waste. Other petitioners can file for reconsiderations as well and may file petitions on the definition of solid waste. In the meantime, the rule is still in effect. The enforcement date remains in effect. EPA can stay the effect of the rule for 90 days by putting a notice in the Federal Register. EPA can further put a notice in the Federal register for a longer stay. However, then there would likely be an objection under the grounds that the Court had already ordered EPA to put out a rule. The EPA could stay a part of the rule, but this is less likely particularly for the emission limits.

Reconsideration is intended to avoid going to Court. Those that are still unhappy with the rule could presumably sue the EPA and still go to Court. Petitioners have 60 days from the publication in the Federal Register to submit petitions for reconsideration. The likelihood is that EPA will resolve procedural issues, but not substantive issues. Judicial review could be requested for issues that are claimed to be arbitrary, capricious, abuse of discretion, or contrary to law. Other consideration issues could be constitutional questions and procedural defects.

Petitioners can ask for a stay of the rule and EPA has to respond. Congress has been very involved with this issue. Congressional review is a possibility. A resolution of disapproval would have to pass both Houses of Congress and be signed by the President. The President has directed all agencies to review their rules and regulations for cost, redundancy, obsolescence, etc. However, since an Executive Order is not a law, this approach will have little traction. Congress could provide legislation that directed EPA to stay the rule and meet a certain time line for a better rule. The House Appropriations battle that is currently underway does not offer much flexibility in working on a fix. Stand-alone legislation is thus the most likely outcome.

A bill is being prepared that will give EPA the time period that they requested from the Court to fix the rule, extend the compliance date accordingly, and to take direction from Congress on the MACT Hammer. Again, this bill will have to be passed by both Houses and be signed by the President. Since this would not be disapproval, but a more positive directive, there would at least be a better chance for this approach to succeed. There will be a letter in your e-mail from Candy asking for volunteers to participate in the activities to prepare comments, petitions, and Congressional support.

RCRA Ash – Gary Merritt, Inter-Power/AhlCon Partners, L.P.

EPA received 450,000 comments regarding the proposed rules (400,000 e-mail from environmental groups, 30,000 e-mail from industrial organizations, but 10,000 substantive comments). The OSMRE is looking at a rule for disposal vs. beneficial use. They will not go forward if EPA chooses Subtitle C. The environmental groups are threatening to sue if a rule is not out in October. These groups continue to publish misleading reports on the "hazards" of coal ash. The House passed an amendment forbidding EPA to use any funds to enforce a Subtitle C determination. However, with all of the budget maneuvering going on, no one really knows what will happen. EPA seems to be holding off for the moment to try to get a better opportunity later.

GHG Regulatory Update – Maxine D. Dewbury, The Procter & Gamble Company,

The GHG reporting rule is in effect. However, EPA has announced a deferral of reporting requirements until the summer as they were not ready. One of the issues is confidential business information. EPA proposed to make public any information used to make GHG emissions estimates. This would mean production data, for example, would become public. In Dec., EPA proposed that certain data elements would be treated as CBI. Now they have agreed to defer the reporting requirement to August 31, 2011. Comments have been submitted on CBI treatment. With the issuance of the light duty vehicle rule, GHGs became a regulated pollutant. This triggered problems with the threshold levels of 100/250 ton/yr (a 0.5 MMBTU/hr burner). EPA issued the "Tailoring Rule" to raise this limit temporarily. Once a unit becomes a major source for one pollutant, it becomes a major source for all. These impacts permit requirements for all criteria pollutants. Further, PSD permits are based on "potential to emit" rather than actual emissions.

In November, EPA issued BACT Guidance for GHGs. New Source Performance Standards are in the planning stages. As of Jan. 1, 2011, sites that needed a PSD permit had to include GHGs. As of July 1, 2011, GHG permitting for PSD will be required. As a result, permitting will be more costly, will take longer, will attract more law suits, and will increase in number. For GHG BACT, energy efficiency is the center piece. However, CCS must be considered and demonstrated that it is not viable. For a new facility, the entire plant efficiency must be considered. The guidance prohibits project netting in Step 1. Guidance includes consideration of CCS, fuel switching, and substantial changes to the source. EPA allows states to expand the definition of the source beyond the emissions unit being modified. Work practices would be better than emission limits. In the case of Ohio, the governor signed an emergency rule to adopt the Tailoring Rule thresholds so that the normal state rules would not apply. Texas is in litigation and will not issue GHG permits.

EPA GHG Permitting Guidance – Robert (Rob) Kaufmann, Koch Companies Public Sector, LLC

Rob reported on some state information, the Nucor permit, and the GHG NSPS. The survey covered a mix of states across the country. General comments were that the guidance was over reaching, particularly with respect to fuel switching and redefining the source. The way the guidance is laid out, the permit applicant is now more subject to challenge. It will take a long time to get a permit. Netting is going to be difficult. Efficiency projects have to be enforceable, quantifiable, reliable, verifiable, and surplus to be counted. The states are not happy with the treatment of biomass. The cost effectiveness level was noted in a white paper with a range of \$3-\$150/ton CO2(e). There will be "technical corrections" to be issued on the guidance document soon. These corrections will not be substantive. The biomass exemption is planned to be finalized by July 1, 2011.

If, after Jan. 2, 2011, you are a minor source for criteria pollutants, but major for GHGs and have not started construction by July 1, 2011, you must obtain a GHG PSD permit. Otherwise, you are constructing a major source without a PSD permit. The Nucor permit was for a "Direct Reduced Iron" (DRI) plant in Louisiana (Region 6). The draft permit had no numerical CO2 limit for the package boiler. There was no baseline GHG data. The permit did not evaluate Carbon Capture and Sequestration (CCS). There was no rationale for not including CO2 analyzers as a monitoring method. A "no more than" gas limit was deemed not practically enforceable. The state response was to set an output based efficiency standard of 13 MMBTU/ton of DRI. CCS was declared to be not feasible as there was no sequestration site available. A baseline emissions calculation was made. CO2 monitors were required. A modification was made for the gas limitation. EPA HQ team will likely review all Regional Office (RO) letters to states. The permit should be "consistent" with the EPA guidance. A justification will likely be required for lack of a CO2 emissions limit.

EPA may set up a new web site to address issues. The RACT/BACT Clearinghouse will include GHG permits. For the GHG NSPS, EPA has agreed to a proposal for utilities by July 26, 2011 with a final rule by May 26, 2012. For refineries, the dates are 12/10/2011 and 11/10/2012. Future plans include pulp and paper, chemicals, and industrial boilers. Utilities have recommended market based approach including trading, banking, fleet wide averaging, incentives for early retirement of older coal plants, and credits for early action. Refineries consider the Clean Air Act as an inappropriate tool and that they are trade exposed and energy intensive. NSPS can be applied to new/modified sources and existing sources under Section 111(d). There are also NSR considerations.

Clean Air Transport Rule – William (Bill) Campbell, III, AECOM Environmental

EPA has stated that the rule is on schedule for finalization. The comment period is closed. The rule addresses the 1997 ozone and PM2.5 NAAQS standards. The precursors to ozone and PM2.5 are NOx and SO2. The EPA has looked at utility units in their 2005 database and modeled the emissions. They have proposed an additional 71% reduction in SO2 and an additional 52% reduction in NOx. There is limited trading in the rule. The EPA has indicated that other sectors are being evaluated for the future. Also, the next round of NAAQS will also lower the emissions rates in order to model out. The first wave of requirements comes into effect of 2012. The second round of compliance for units that have to construct controls comes in 2014. There is an "opt in" provision for large industrial boilers. The compliance date for Industrial Boiler MACT is also 2014.

NAAQS – Robert (Rob) Kaufmann, Koch Companies Public Sector, LLC

The Ozone Rule is now due to go final on July 29, 2011. The final standard will be in the range of 60 - 70 ppb. New ozone monitors for many areas will be required. California and the Northeast Coast were essentially in non-attainment for the old standard. In the last few years, the number of non-attainment areas has declined. There were only 112 counties in non-attainment. There is already a plan for a revised standard in 2013. The current rule is from 2008 at 75 ppb. Non-attainment SIPs will be due in 2016. One proposal is to scrap the revisions to the 2008 rule in 2011 and focus on the new rule in 2013. For the PM2.5 standard of 15 micrograms/m3 for the annual standard, the proposal is to go to 11 - 13 mg/m3. The 24 hour standard is 35 mg/m3. There were only 35 counties in non-attainment. With the reduced standard, there will be 366 counties in non-attainment.

The PM2.5 revision standards have been delayed and will like come out this fall and go final in 2012. The first deadline would be Dec. 2012. The second deadline would be in 2016.

The SO2 1 hour standard is proposed to be 75 ppb. There are 59 counties in 22 states that would violate the new standard. For this standard, states must use modeling and monitoring for classification. For areas that are unclassifiable (i.e. with not monitors), maintenance SIPs will be required. Maintenance SIPs must demonstrate, through refined modeling, that all sources contributing potential non-attainment (sources greater than 100 ton/yr SO2). States must model impacts from about 2000 sources in 1000 counties. Maintenance SIPs will be due in June 2013. Non-attainment SIPs are due in Feb. 2014. Attainment is due in June 2017.

This focus on modeling is being litigated. The states and the EPA do not have the resources to handle the level of the models. The EPA modeling group has suggested that facilities work with the Regional Offices. There will be a workshop in Atlanta in June. There will a Modeling Conference in October. The modeling group has indicated the next round of the Clean Air Transport Rule will be a national rule (not just east of the Mississippi). It will likely include large industrial units if they were under the NOx SIP call. A Guidance Memo was issued on March 1st addressing some problems with the modeling. Some of the conservatism in the approach has been taken out. States can eliminate intermittent units and start-up/shut down emissions from modeling scenarios. More generous default values for NO2 and for NO2/NOx in-stack ratios were given. Less conservative monitored background concentrations can be utilized.

Emission Factor Improvements – Maxine D. Dewbury, The Procter & Gamble Company

Maxine asked for help with comments on the use of these factors. EPA is calling for the use of statistical adjustments when emission factors are used for permits. This could have some policy issues. EPA conducted an emission factor uncertainty review in 2007. EPA had proposed that multipliers be used to account for uncertainty in the factors. Comments at that time suggested that EPA deal with the implications of this approach. In December 2009, EPA proposed some changes to the emission factor program. Emissions factors are used for small sources without test data and monitoring equipment.

Another issue was the requirement to report data through the EPA's electronic reporting tool. One comment was to fix the tool before requiring people to use it. EPA has made progress in this area. When there are changes to an emission factor, an existing unit has not increased its emissions. Only the factor has changed. State permits need to be adjusted accordingly. This becomes an issue in states that insist on listing every possible emission in a permit. One improvement has been that EPA has provided the background basis for the emission factor so that facilities can, perhaps, look at similar sources and come up with their own emissions factors.

GOVERNMENT AFFAIRS SESSION

Anthony Reed, Archer Daniels Midland Company**,** *Government Affairs Committee Chairman*

Anthony Reed, Archer Daniels Midland Company, The new Congress has a different dynamic. The House is completely different. A number of conservative individuals have been elected to the House. The Republican Study Committee (the conservative wing) now covers 1/3 of the House members. The Senate now has a 3 seat majority for the Democrats (as opposed to 10). With this kind of a Congress, it is important to emphasize member to member positions. There is a lot of legislative activity. Chairman Upton has a bill that is being marked up in the energy subcommittee that would delay GHG legislation. There is also a bill to delay the implementation of the Boiler MACT. Oversight committees will be pouring over EPA. In the case of energy, the House appears to be approaching the problem on an issue by issue basis. With energy prices increasing, anything can happen as Congress is called upon to "do something". A number of bipartisan letters were sent to the administration and the EPA on Industrial Boiler MACT, supporting the EPA requested delay in implementation of the proposed rule (not granted by the Court).

Chris Keuleman, International Paper noted that the EPA put a positive spin on the release of the Boiler MACT rule with their announcement that they had cut the estimated cost in half. This has given the impression that EPA has "fixed" the rule. Such is not the case. Continued diligence is needed to get across the point that this is a costly rule that needs more work. The luncheon speaker is Dave McCarthy, Chief Counsel of the Environment and Economy Subcommittee of the Energy and Commerce Committee of the House of Representatives. He will talk about Environmental legislation in 2011. The two biggest issues are the Health Based Emission Limits and achievability of some of the standards. It would be desirable if the EPA could get the time that they requested for the rule with a concomitant extension of the compliance date. Legislation to that effect could be helpful. On energy efficiency, CIBO can be a resource. The definition of cogeneration and EGU are important. CIBO supports the Acid Rain Title IV definition. The Senate is considering an Energy Efficiency Bill that will cover building energy codes, appliance standards, home/commercial building financing, federal energy efficiency, worker training, incentives for efficient plants, manufacturing R&D, light duty vehicle improvements, and tire efficiency and gauge standards.

Karen Neale, Hummingbird Strategies, a CIBO consultant reviewed the schedule for three member teams to visit twelve different Senate offices to impress upon them that while EPA may have provided some relief for Natural Gas fired units and small and limited use units, it does not look like anything they did will be of significant help to the solid fuel fired units across the country. Also, to indicate EPA needs more time to be able to address the short comings of the rule, assess the economic impact of the rules and have ample time for building a record to support new subcategories, work practice standards and changes to emission limits that will surely be challenged in court by the ENGOs. After CIBO has a chance to review the rules in detail and assess how compliance can be achieved, if it can be achieved, and at what cost, we may at that time have specific requests for this Congress.

Next Technical Focus Group/Environmental & Energy Committee Meetings
TUESDAY & WEDNESDAY, JUNE 7-8, 2011
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