FINAL REPORT

Small Business Advocacy Review Panel on EPA's Rulemaking for

Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units

February 16, 2011

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Final Report for the Small Business Advocacy Review Panel on EPA's Planned Proposal of National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units

1. INTRODUCTION

This report is presented to the Small Business Advocacy Review Panel (SBAR Panel or Panel) convened for the planned proposed rulemaking on the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-Fired Electric Utility Steam Generating Units (Utility NESHAP) currently being developed by the U.S. Environmental Protection Agency (EPA). Under section 609(b) of the Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), a Panel is required to be convened prior to publication of the initial regulatory flexibility analysis (IRFA) that an agency may be required to prepare under the RFA. In addition to EPA's Small Business Advocacy Chairperson, the Panel will consist of the Director of EPA's Sector Policies and Programs Division within the Office of Air Quality Planning and Standards, the Administrator of the Office of Information and Regulatory Affairs within the Office of Management and Budget, and the Chief Counsel for Advocacy of the Small Business Administration.

This report includes the following:

- background information on the proposed rule being developed;
- information on the types of small entities that would be subject to the proposed rule;
- a description of efforts made to obtain the advice and recommendations of representatives of those small entities; and
- a summary of the comments that have been received to date from those representatives.

RFA section 609(b) directs the Panel to report on the comments of small entity representatives and make findings on issues related to identified elements of IRFA under RFA section 603. Those elements of an IRFA are:

- a description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply;
- projected reporting, record keeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirements and the type of professional skills necessary for preparation of the report or record;

- an identification, to the extent practicable, of all other relevant Federal rules which may duplicate, overlap, or conflict with the proposed rule; and

- any impacts on small entities and any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities.

Once completed, the Panel report is provided to the agency issuing the planned proposed rule and included in the rulemaking record. In light of the Panel report, and where appropriate, the agency is to make changes to the draft proposed rule, the IRFA for the proposed rule, or the decision on whether an IRFA is required.

It is important to note that the Panel's findings and discussion will be based on the information available at the time the final Panel report is drafted. EPA will continue to conduct analyses relevant to the proposed rule, and additional information may be developed or obtained during the remainder of the rule development process. The Panel makes its report at a preliminary stage of rule development and its report should be considered in that light. At the same time, the report provides the Panel and the Agency with an opportunity to identify and explore potential ways of shaping the proposed rule to minimize the burden of the rule on small entities while achieving the rule's purposes.

Any options identified by the Panel for reducing the rule's regulatory impact on small entities may require further analysis and/or data collection to ensure that the options are practicable, enforceable, environmentally sound, and consistent with the Clean Air Act (CAA).

2. BACKGROUND

2.1 Background and Regulatory History

In December 2000, EPA made a finding that it was appropriate and necessary to regulate coal- and oil-fired electric utility steam generating units (EGUs) under CAA section 112 and listed EGUs pursuant to CAA section 112(c). On March 29, 2005 (70 FR 15994), EPA published a final rule (Section 112(n) Revision Rule) that removed EGUs from the list of sources for which regulation under CAA section 112 was required. That rule was published in conjunction with a rule requiring reductions in emissions of mercury from electric utility steam generating units pursuant to section 111 of the CAA (Clean Air Mercury Rule (CAMR), May 18, 2005, 70 FR 28606). The Section 112(n) Revision Rule was vacated on February 8, 2008, by the U.S. Court of Appeals for the District of Columbia Circuit. As a result of that vacatur, CAMR was also vacated and EGUs remain on the list of sources that must be regulated under CAA section 112.

In the December 2000 regulatory determination, EPA made a finding that it was appropriate and necessary to regulate EGUs under CAA section 112. The February 2008 vacatur of the Section 112(n) Revision Rule reverted the status to that of the December 2000 regulatory determination. CAA section 112(n)(1)(A) and the 2000 determination do not differentiate between EGUs located at major versus area sources of hazardous air pollutants (HAP). Thus, the NESHAP for EGUs will regulate units at both major and area sources. Major sources of HAP are those that have the potential to emit 10 tons per year (tpy) or more of any one HAP or 25 tpy or more of any combination of HAP.

2.2 Description of the Rule and its Scope

The "electric utility steam generating unit" source category includes those units that combust coal or oil for the purpose of generating electricity for sale and distribution through the national electric grid to the public. CAA section 112(a)(8) defines an "electric utility steam generating unit" as:

> any fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered an electric utility steam generating unit.

The source category includes investor-owned units as well as units owned by the Federal government, municipalities, and cooperatives, among others. These units provide electricity for commercial, industrial, and residential uses. Currently, coal-fired generating units typically supply "base-load" electricity, which means these units operate continuously throughout the day and meet the part of electricity demand that is relatively constant. Oil-fired generating units typically supply "peak" power, when there is increased demand for electricity (e.g., when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning, versus late at night or very early morning when demand for electricity is reduced). Coal- and oil-fired EGUs have the potential to emit many HAP.

Coal-fired EGUs include units that burn coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other supplemental fuels. Examples of supplemental fuels included petroleum coke and tire-derived fuels. Oil-fired EGUs include units that burn liquid oil or solid oil-derived fuel (i.e., petroleum coke). The NESHAP will establish standards for HAP emissions from both coal- and oil-fired EGUs and will apply to any existing, new, or reconstructed units located at major or area sources of HAP. Although all HAP are pollutants of interest, those of particular concern are hydrogen fluoride (HF), hydrogen chloride (HCl), dioxins/furans, and HAP metals, including antimony, arsenic, beryllium, cadmium, chromium, cobalt, mercury, manganese, nickel, lead, and selenium.

In developing the vacated CAMR, EPA identified a total of 81 potentially affected small entities with coal-fired EGUs and determined that CAMR would not have a significant impact on a substantial number of those small entities. That determination was based on the fact that the final rule would not establish requirements applicable to small entities, other than new sources. At that time, EPA projected no new construction of coal-fired utility units.

Additionally, CAMR did not establish requirements applicable to existing small entities because the final rule made allowances available to each State; the States were then to distribute their allowances to the EGUs within their State according to their individual situations. Based on current information, we have identified approximately 525 facilities with 1,350 individual coal- or oil-fired units. We estimate that 80 companies that own coal- or oil-fired EGUs are small entities.

2.3 Related Federal Rules

As noted above, the "electric utility steam generating unit" source category includes those units that combust coal or oil for the purpose of generating electricity for sale and distribution through the national electric grid to the public. Because of the definition provided in CAA section 112(a)(8), there should not be any EGU that is regulated under another CAA section 112 regulation.

Combustion units that burn fossil fuels but do not meet the size or electric distribution requirements of CAA section 112(a)(8) will be covered under the CAA section 112(d) rules for Industrial, Commercial, and Institutional Boilers (Area and Major Source Boiler NESHAPs), which were proposed on June 4, 2010 (75 FR 31896 and 75 FR 32006). Combustion units that burn a solid waste as defined by the Administrator will be covered as solid waste incineration units under CAA section 129. However, combustion units that burn a homogeneous solid waste and are qualifying units and are thus exempt from regulation under CAA section 129 under the provisions of CAA section 129(g)(1)(B) will be covered under the Utility NESHAP if they combust fossil fuel and meet the size and electric distribution requirements of CAA section 112(a)(8); otherwise they will likely be covered under one of the Boiler NESHAPs (final action required by February 21, 2011).

In 2007, EPA revised new source performance standards (NSPS) for EGUs having a heat input capacity greater than 250 million Btu per hour (40 CFR part 60, subpart Da). The NSPS regulates emissions of particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_X) from boilers constructed after June 2007. EPA is currently working on additional revisions to the PM, SO_2, and NO_X emissions limits in subpart Da. Those revisions will be proposed and promulgated along with the Utility NESHAP on March 16, 2011 and November 16, 2011, respectively. Sources subject to the NSPS would also be subject to the Utility NESHAP because those rules regulate sources of HAP whereas the NSPS does not. However, in developing the NESHAP for EGUs, EPA will minimize the monitoring requirements, testing requirements, and recordkeeping requirements to avoid duplicating requirements to the extent possible.

On June 3, 2010 (75 FR 31514), EPA issued a final rule that establishes thresholds for greenhouse gas (GHG) emissions that define when permits under the New Source Review Prevention of Significant Deterioration (PSD) and title V Operating Permit programs are required for new and existing industrial facilities (the Tailoring Rule). The final rule addresses emissions of six GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). As of January 2, 2011, large industrial sources, including power plants, are subject to permitting requirements for their GHG emissions if they otherwise are required to obtain a PSD or title V permit due to emissions of other air pollutants.

On December 23, 2010, EPA announced a settlement agreement, subject to CAA section 113(g) public comment, under which it would issue a proposed rule under CAA section 111(b) that includes standards of performance for GHGs for new and modified EGUs as well as issuing a proposed rule under CAA section 111(d) that includes emission guidelines for GHGs from existing EGUs . The rules would establish NSPS for new and modified EGUs and emission guidelines for existing EGUs. In addition to the NSPS requirements established for new and modified sources under section 111(b) of the CAA, for pollutants not regulated under other parts of the CAA, EPA must establish emission guidelines under CAA section 111(d) that States use to develop plans for reducing emissions from existing sources. The guidelines include targets based on demonstrated controls, emission reductions, costs and expected timeframes for installation and compliance, and can be less stringent than the requirements imposed on new sources. Under the agreement, EPA commits to issuing these proposed regulations by July 26, 2011 and, after considering any public comments received concerning the proposed rule(s), a final rule that takes final action with respect to the proposed rule(s) by May 26, 2012. At this time the Agency has not formulated a final approach for regulating GHGs from EGUs; however, there is the potential that compliance with requirements of the NESHAP could result in some existing sources becoming new sources for purposes of the NSPS.

On August 2, 2010 (75 FR 45210), EPA proposed a rule that would require 31 states and the District of Columbia (D.C.) to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states (the Clean Air Transport Rule). Specifically, the proposal would require reductions in SO_2 and NO_X emissions that cross state lines. In response to a December 2008 court decision, the proposed Transport Rule would replace EPA's remanded 2005 Clean Air Interstate Rule (CAIR). The Transport Rule is expected to be finalized in July 2011. To the extent that EGUs are located in the final set of states or D.C., they would be subject to the Transport Rule.

Based on the findings from EPA's multi-year study of the Steam Electric Power Generating industry, EPA plans to revise the current effluent guidelines under the Clean Water Act (CWA) that apply to steam electric power plants. EPA evaluated waste streams generated at power plants, including wastewaters from wet flue gas desulfurization (FGD) air pollution control systems, fly ash and bottom ash handling, coal pile runoff, condenser cooling, equipment cleaning, and leachate from landfills and impoundments, but ultimately focused largely on discharges associated with coal ash handling operations and wastewater from FGD systems because these sources comprise a significant fraction of the pollutants discharged by steam electric power plants. EPA is required by consent decree to propose revised effluent guidelines in July 2012 and to finalize the guidelines in January 2014.

Section 316(b) of the CWA requires EPA to establish best technology available standards to minimize adverse environmental impacts from cooling water intake structures. In developing these standards, EPA divided its effort into three rulemaking phases. Phase I, for new EGU plants using cooling water, was promulgated on December 18, 2001 (66 FR

65255). Minor revisions to the Phase I rule were finalized on June 19, 2003 (68 FR 36749). Phase II, for existing EGU plants that use at least 50 million gallons per day (MGD) of cooling water, was promulgated on July 9, 2004 (69 FR 41576). Those regulations were challenged, and several provisions of the Phase II rule were remanded on various grounds. EPA suspended most of the rule in response to the remand (72 FR 37107, July 9, 2007). On June 16, 2006 (71 FR 35005), EPA promulgated the Phase III regulations covering existing EGU plants using less than 50 MGD of cooling water. Those regulations also were challenged, and EPA requested, and was granted, a partial remand. EPA plans to issue regulations that address both Phase II and III facilities. EPA signed a settlement agreement that requires those regulations to be proposed by March 14, 2011, and promulgated by July 27, 2012.

On June 21, 2010 (75 FR 35128), EPA proposed national rules for the management of coal combustion residuals under the Resource Conservation and Recovery Act (RCRA). Coal combustion residuals, commonly known as coal ash, are residues from the combustion of coal in power plants and are captured by pollution control technologies, like scrubbers. The residues are disposed of in liquid form at surface impoundments and in solid form at landfills. EGUs will be subject to these coal ash specific regulations when they are issued. The date of final action has not yet been determined.

3. OVERVIEW OF PROPOSAL UNDER CONSIDERATION

3.1 Potential Requirements of the Proposal

As explained above, in the December 2000 regulatory determination, EPA made a finding that it was appropriate and necessary to regulate EGUs under CAA section 112. Voluntary and incentive-based approaches are not available for these standards. The proposed standards must set technology-based limits as appropriate, but we will explore the viability of other rulemaking options, such as work practices standards and health based standards. A work practice standard, instead of emission standards, may be proposed for major sources if it is not feasible to prescribe or enforce an emission standard. CAA section 112(h)(2)(B) defines, in part, "not feasible to prescribe or enforce and emission standard" to mean that "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations." CAA section 112(d)(4) provides EPA with discretionary authority to establish health-based emission standards for HAP for which a health threshold has been established. The provision is intended for cases where an alternative emission standard will still ensure that the health threshold will not be exceeded, with an ample margin of safety.

CAA section 112(d)(2) requires standards for major sources be based on the maximum achievable control technology (MACT). CAA section 112(d)(3) sets minimum stringency criteria (MACT Floor) for these standards. For existing sources, the standards shall not be less stringent than "the average emission limitation achieved by the best performing 12 percent of existing sources...." For new sources, the MACT floor is "the emission control achieved in practice by the best controlled similar source…." Costs may not be considered when determining MACT floors. EPA must consider regulatory options more stringent than the MACT floor and may regulate "beyond the floor" where justified. Beyond-the-floor options can include additional control technologies, process changes, or other means of reducing HAP. Costs and other impacts/issues must be considered when assessing beyond-the-floor options.

Since the inception of the MACT program, EPA has consistently maintained that the "pollutant-by-pollutant" approach to setting floors is the appropriate approach. *See e.g.* 61 FR at 17368 (April 19, 1996). The "pollutant-by-pollutant" approach entails determining the best performing unit or units in the category for each HAP and establishing the MACT floor separately for each HAP (or group of HAP if a surrogate standard is established). Under this approach, the units on which the MACT floor are based may be different for each HAP if, for example, the best performing units for one HAP are poor performers for other HAP. It has been suggested that MACT floors should be established using a facility-wide approach. The concerns associated with the facility-wide approach are discussed below.

The court has ruled that "no emission reduction" MACT floors (resulting in no emission limits being set) are unlawful. See Sierra Club v. EPA, 479 F.3d 875, 883. Thus, the proposal will contain limits for HAP for all affected EGUs. We are considering developing emission limits for particulate matter (PM) (as a surrogate for non-mercury HAP metals), mercury, hydrogen chloride (HCl) or sulfur dioxide (SO_2) (as a surrogate for HAP acid gases), dioxin/furan, and carbon monoxide (CO) or other pollutants (e.g., polycyclic aromatic hydrocarbons (PAH) or formaldehyde) (as a surrogate for non-dioxin/furan organic HAP). The court has stated that the use of surrogate standards is allowed if it can be demonstrated that the surrogate standards are reasonable. For example, the recently promulgated NESHAP for the Portland Cement Manufacturing Industry includes emission limits for PM, mercury, HCl, dioxin/furan, and THC (75 FR 54970, September 9, 2010). In addition, the proposed Major Source Boiler NESHAP includes limits for PM, mercury, HCl, dioxin/furan, and CO (75 FR 32006, June 4, 2010). Based on the similarities in types of HAP emitted from industrial/commercial/institutional boilers and EGUs, the Major Source Boiler NESHAP proposal provides an estimation of potential control technologies that may represent those predominantly used by EGUs in the MACT floor and that may result in the emission reductions necessary to meet the standards for the various emissions from coal- and oil-fired EGUs. For example, the average PM emission limitation (as a surrogate for non-mercury HAP metals) achieved by the best performing EGUs is likely to be based on a fabric filter-controlled EGU, and use of a fabric filter will likely achieve the PM emission limit. For the various pollutants likely to be regulated under the Utility NESHAP, the estimated control technologies are:

- PM/non-mercury HAP metals = Fabric Filters
- Mercury/dioxin/furan = Activated carbon injection
- HCl/SO_2/acid gas HAP = Wet or dry scrubber
- CO/PAH/formaldehyde/non-dioxin/furan organic HAP = Good combustion practices

The court also indicated that when determining variability, sources outside the MACT floor may not be considered unless a demonstrated relationship between the variability of sources outside the floor and the variability of sources within the floor can be shown. In characterizing variability of the best performing EGUs, we may include fuel variability and performance variability. In addition, we will look at load variability. Recent regulatory actions (e.g. the Major Source Boiler NESHAP proposal, final NESHAP for Portland Cement Manufacturing Industry) assessed variability based on the 99th percentile upper predictive limit (UPL). The 99th percentile UPL means that for a future test from a best performing source, there is 99 percent confidence that the reported level will fall at or below the UPL value.

CAA section 112(d)(1) provides EPA with the authority to distinguish among classes, types, and sizes of sources in establishing standards. However, there must be a basis for distinguishing between subcategories (e.g., design differences, operating mode (continuous or batch), or other characteristics). Data necessary to establish MACT floors are required for each subcategory that is identified.

In order to make the determinations necessary to develop the proposal, EPA has essentially completed an effort to collect facility information (e.g., boiler types, fuels combusted, control technologies) and available emissions data from 1,332 EGUs (requiring approximately 800 EGUs to conduct emissions testing). To date, facility information and available emissions data from the past 5 years have been received from almost all of the units. Emissions test results have been received from over 99 percent of the EGUs required to conduct testing.

3.2 Options Likely to be Proposed

EPA is still developing the proposal. EPA has not yet decided on a detailed approach for subcategorizing the source category, determining the MACT floor, or the compliance requirements. As EPA is developing the proposed rulemaking, EPA is also discussing appropriate options that would, consistent with the CAA, ease the compliance burden for small businesses that may be affected by the rule while maintaining the overall goals of the program. EPA will continue to seek input from small entities throughout the regulatory development process. Potential options must be assessed in light of the CAA and current case law. Some potential options to assist small entities in compliance with the new rule requirements are discussed below.

All HAP emitted from EGUs must be addressed by the Utility NESHAP. Surrogate standards are allowed if reasonable. Regardless of whether emission standards are established for HAP or for surrogate pollutants, the same control technologies (or process changes or other means of reducing HAP) would be installed in order to comply with those standards. Use of surrogate standards has the potential to reduce monitoring and testing costs imposed on affected entities.

One likely option is to establish subcategories based on boiler design (e.g., units designed to burn coal versus units designed to burn oil versus integrated gasification combined cycle (IGCC) systems (burning of synthetic gas)). Other options include subcategorizing EGUs by duty cycle (e.g., peaking units versus base-load units), subcategorizing coal-fired EGUs by coal rank (e.g., bituminous, subbituminous, lignite) and/or unit type (e.g., fluidized bed, pulverized coal), and subcategorizing oil-fired EGUs by oil type (e.g., residual, distillate). Additional potential options include the use of work practice or management practice standards, health-based emission levels, emissions averaging within a facility, reduced monitoring/testing requirements, or allowing more time for compliance, as long as they are consistent with the provisions of the CAA.

Although emission standards are often structured in terms of numerical emissions limits, alternative approaches are sometimes necessary and authorized pursuant to CAA section 112. In some cases, physically measuring emissions from a source may not be practicable due to technological and economic limitations. CAA section 112(h) authorizes the Administrator to promulgate a design, equipment, work practice, or operational standard, or combination thereof, consistent with the provisions of CAA sections 112(d) or (f), in those cases where, in the judgment of the Administrator, it is not feasible to prescribe or enforce an emission standard for major sources. As previously explained, section 112(h)(2) provides that the phrase “not feasible to prescribe or enforce an emission standard” includes the situation in which the Administrator determines that the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

Under CAA section 112(d)(5), EPA may elect to promulgate standards or requirements for area sources “which provide for the use of generally available control technologies or management practices (‘GACT’) by such sources to reduce emissions of hazardous air pollutants.” Consistent with the legislative history, costs and economic impacts may be considered in determining GACT. Determining what constitutes GACT involves considering the control technologies and management practices that are generally available to the area sources in the source category. The standards applicable to major sources in the analogous source category also are considered to determine if the control technologies and work practices are transferable and generally available to area sources. In appropriate circumstances, technologies and practices at area and major sources in similar categories may be considered to determine whether such technologies and practices could be considered generally available for the area source categories at issue.

As a general matter, section 112(d) of the CAA requires MACT standards at least as stringent as the MACT floor to be set for all HAP emitted from major sources. However, section 112(d)(4) provides that for HAP with established health thresholds, the Administrator has the discretionary authority to consider such health thresholds when establishing emission standards under section 112(d). This provision is intended to allow EPA to establish emission standards other than conventional MACT standards in cases where the alternative emission standard would ensure that the health threshold will not be exceeded, with an ample margin of safety. To exercise this discretion, EPA must first conclude the HAP at issue has an established health threshold and must then provide for an ample margin of safety when considering the health threshold to set an emission standard. EPA has exercised its discretionary authority under CAA section 112(d)(4) in a handful of prior actions setting emissions standards for other major source categories, including the emissions standards issued in 2004 for commercial and industrial boilers and process heaters, which were vacated on other grounds by the D.C. Circuit Court. In both the Pulp and Paper NESHAP, 63 FR 18765 (April 15, 1998), and Lime Manufacturing NESHAP, 67 FR 78054 (December 20, 2002), EPA invoked CAA section 112(d)(4) for HCl emissions for discrete units within the facility. In those actions, EPA concluded that HCl had an established health threshold and was not classified as a human carcinogen. In light of the absence of evidence of carcinogenic risk, the availability of information on non-carcinogenic effects, and the limited potential health risk associated with the discrete units being regulated, EPA concluded that it was appropriate to exercise its discretion under CAA section 112(d)(4) for HCl under the circumstances of those actions. In a more recent action, EPA decided not to propose a health-based emission standard for HCl emissions under CAA section 112(d)(4) for Portland Cement facilities, 75 FR 54970 (September 9, 2010). EPA has never implemented a NESHAP that used section 112(d)(4) authority with respect to the other HAP acid gases of hydrogen fluoride (HF), chlorine (Cl_2), and hydrogen cyanide (HCN).

EPA has a general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining regulation that is workable and enforceable. Emissions averaging allows an affected source to demonstrate that the source complies with the emission limits by averaging the emissions from an individual affected unit that is emitting above the emission limits with other affected units at the same facility that are emitting below the emission limits. EPA has generally imposed certain limits on the scope and nature of emissions averaging. These limits include no averaging between different types of pollutants; no averaging between sources that are not part of the same affected source; no averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP; and no averaging between existing sources and new sources.

EPA's standards must establish requirements that are adequate to assure continuous compliance with the rule. In some instances, that can be achieved without significant additional burden for facilities that must implement the rule. For example, use of surrogate pollutants may result in reduced compliance costs because testing would only be required for the surrogate pollutants (e.g., PM) versus the HAP (e.g., all non-mercury HAP metals). Continuous monitoring of control device parameters, rather than continuous monitoring of emissions, results in reduced monitoring costs. Standards based on work practices or management practices in lieu of emission limits also result in reduced compliance costs because testing and continuous monitoring would not typically be required.

Section 112 of the CAA specifies the dates by which affected sources must comply with the emission standards. New or reconstructed units must be in compliance with the final rule immediately upon startup or the date that the final rule is published in the Federal Register, whichever is later. Existing units may be allowed up to 3 years to comply with the final rule. EPA has authority to require that existing sources comply in less than 3 years where appropriate. With respect to compliance with the Utility NESHAP, EPA believes that 3 years for compliance is likely necessary to allow adequate time to design, install and test control systems. Section 112(i)(3)(B) of the CAA allows facilities to request a one-year extension to any MACT compliance schedule if such additional time is necessary for the installation of controls. The extension is not automatic and may be provided on a case-by-case basis by each facility's permitting authority based on a request by the affected facility. The President may exempt any stationary source from compliance with any standard or limitation under CAA section 112 for a period of not more than 2 years if the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so (see CAA section 112(i)(4)). An exemption under this provision may be extended for one or more additional periods, each period not to exceed 2 years.

4. APPLICABLE SMALL ENTITY DEFINITIONS

For purposes of assessing the impacts of the proposed rule on small entities, small entity is defined as: (1) a small business according to the Small Business Administration (SBA) size standards by the North American Industry Classification System (NAICS) category of the owning entity (the range of small business size standards for electric utilities is 4 million megawatt hours of production or less); (2) a small governmental jurisdiction that is a government of a city, county, town, township, village, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. As set by SBA, the categories of small entities that will potentially be affected by this rulemaking are defined in the following table:

Sector	**NAICS Code**	**Defined as small entity by SBA if less than or equal to:**	
		Population	**Size Standard**
Fossil Fuel Electric Power Generation (Industry)	221112	N/A	4 million megawatt hours
Fossil Fuel Electric Power Generation (State/Local Government)	221112	50,000	N/A
Fossil Fuel Electric Power Generation (American Indian and Alaska Native Tribal Governments)	921150	N/A (see footnote)[1]	N/A (see footnote)[1]

EPA used a variety of sources to identify which entities are appropriately considered "small." EPA used the criteria for small entities developed by SBA under the NAICS

[1] As stated in the current SBA small business size standards: NAICS Sector 92 – Small business size standards are not established for this sector. Establishments in the Public Administration sector are Federal, State, and local government agencies which administer and oversee government programs and activities that are not performed by private establishments. Concerns performing operational services for the administration of a government program are classified under the NAICS private sector industry based on the activities performed. Similarly, procurements for these types of services are classified under the NAICS private sector industry that best describes the activities to be performed. For example, if a government agency issues a procurement for law enforcement services, the requirement would be classified using one of the NAICS industry codes under NAICS industry 56161, Investigation, Guard, and Armored Car Services.

code(s) as a guide.[2] Utility NESHAP information collection request (ICR) responses and data from other Agency actions (e.g., Clean Air Interstate Rule, proposed Transport Rule) were used to identify facilities. EPA then found revenue, employment, and population information for parent entities using sources including Dun and Bradstreet, Standard & Poor's, American Business Information, the Energy Information Administration (EIA) within the U.S. Department of Energy, the U.S. Census Bureau, and Ventyx.

5. SMALL ENTITIES THAT MAY BE SUBJECT TO THE PROPOSED REGULATION

The estimated number of small entities that will be potentially subject to the Utility NESHAP, as required by CAA, include 66 small State/local governments and 14 small non-government entities. These numbers reflect additions and deletions to the initial list of potentially impacted small entities as suggested by SERs as appropriate. EPA is aware of EGUs located in Indian Country but is not aware of any EGUs owned by Tribal entities. Potentially affected small entities are presented in the following table:

Alexandria LA (City of)	Dalton GA (City of)	Los Alamos County	Sam Rayburn G & T Electric Coop Inc
Algona Municipal Utilities	Dover DE (City of)	Louisiana Energy & Power Authority	San Miguel Electric Coop Inc
Alta IA (City of)	East Power Corporation	Lyndonville Electric Dept	Sikeston Utilities
American Consumer Industries Inc	East Texas Electric Coop	Manitowoc Public Utilities	South Mississippi Electric Power Association
American Consumers Inc	Eldridge IA (City of)	Marquette Board of Light & Power	Southern Illinois Power Coop
American Hydropower Company	Farmington NM (City of)	Milford Municipal Utilities	Southern Minnesota Municipal Power Agency
American Power Investors Inc.	Fort Pierce Utility Authority	Missouri River Energy Services	Spencer Municipal Utilities
Arizona Electric Power Coop	Fremont Dept of Public Utilities	Montezuma Municipal Utilities	Square Butte Electric Coop
Atlantic Municipal Utilities	Geneseo Municipal Utilities	Municipal Energy Agency of Nebraska	Sumner Municipal Light Plant
Austin Utilities	Graettinger Municipal Light Plant	Muscatine Power & Water	Sunflower Electric Power Coop
Azusa CA (City of)	Grand Haven Light & Power	National Energy & Gas Transmission	Tipton IA (City of)
Bancroft Municipal Utilities	Grand Island Utilities	New Hampton Municipal Light Plant	Tondu Corp
Banning Electric Division	Greenville Electric Utility System	North American Power Group Ltd	Utah Associated Municipal Power System
Beowulf Energy LLC	Harlan Municipal Utilities	Northeast Texas Electric Coop Inc	Wabash Valley Power Association Inc
Cedar Falls Utilities	Hastings Utilities (NE)	Northwest Power Coop	Waverly Light & Power
Central Iowa Power Coop	Henderson Municipal Power & Light	Osceola AR (City of)	Webster City IA (City of)
Central Vermont Public Service Corp	Holland Board of Public Works	Pella Municipal Light & Power	West Bend IA (City of)
Colstrip Energy LP	Jonesboro Water & Light	Power Resources Coop	West Memphis Utility Dept
Coon Rapids IA (City of)	Kansas Electric Power Coop	Prairie Power Coop	Winfield KS (City of)
Corn Belt Power Coop	Laurens IA (City of)	Richmond Power & Light	WPPI Energy

[2] The current SBA size standards are found at http://www.sba.gov/idc/groups/public/documents/sba_homepage/serv_sstd_tablepdf.pdf.

EPA's list of potentially affected small entities includes electricity generators. SERs believe that this list should also include distribution cooperatives that own electricity generation and transmission (G&T) cooperatives and that qualify as small entities. SERs stated that the Utility NESHAP will have a direct impact on all electric cooperatives generating and/or distributing coal-based power given the closely interwoven nature of the G&T cooperatives and the distribution cooperatives. SERs explained that any expenditure made by the G&T cooperatives in order to comply with requirements of the Utility NESHAP will be borne in tandem by the distribution cooperatives because the G&T cooperatives are owned by the distribution cooperatives they serve. EPA acknowledges that small entity distribution cooperatives that own generation processes would be impacted in some way by the Utility NESHAP because generation processes will be regulated by the standards, but the extent to which small entity distribution cooperatives would be impacted is unclear without more detailed information on these entities.

6. SUMMARY OF SMALL ENTITY OUTREACH

6.1 Small Entity Outreach

Before beginning the formal SBREFA process, EPA engaged in outreach with entities that would potentially be affected by the upcoming rulemaking to provide an opportunity for discussion of their questions and concerns regarding the upcoming rulemaking. The outreach consisted of meeting with some organizations that represent and include small entities, including the American Public Power Association (APPA), Edison Electric Institute (EEI), the Utilities Air Regulatory Group (UARG), and the Coal Utilization Research Council (CURC). Once the SBAR Panel process began and potential small entity representatives (SERs) were identified, EPA provided each SER with background information on the Utility NESHAP rulemaking process. An outreach meeting with the SERs was held on December 2, 2010.

6.2 Summary of Panel's Outreach Meeting with Small Entity Representatives

The SBAR Panel convened on October 27, 2010. The Panel held a formal outreach meeting/teleconference with SERs on December 2, 2010. To help the SERs prepare for the meeting/teleconference, on November 17, 2010, the Panel sent materials to each of the SERs via e-mail. Representatives from fourteen of the eighteen companies and organizations that were selected as SERs for this SBREFA process participated in the meeting (in person and by phone). There were five non-SER participants from organizations representing power producers. The Outreach Meeting was held to solicit input/suggestions from the SERs regarding the upcoming rulemaking. The meeting was opened by Ken Munis, acting in place of Alex Cristofaro, EPA's Small Business Advocacy Chair, with a short introduction to the Regulatory Flexibility Act (RFA) and SBREFA process, the purpose of the Outreach Meeting, and the importance of the SERs' comments. Following this was a presentation by EPA staff. Information presented included:

- Background

- Project history
- Section 112 overview
- Constraints on rulemaking
- Affected facilities
- Data
- Rulemaking options under consideration
- Potential control technologies and estimated costs
- Applicable small entity definitions
- Small entities potentially subject to regulation
- Questions for SERs

A discussion of issues related to the NESHAP program in general, the potential requirements of the Utility NESHAP, and the regulatory areas where EPA has discretion and could potentially provide flexibility followed the presentation (see section 8.5 for discussions/comments raised during the EPA Outreach Meeting). EPA asked that the SERs provide feedback on the outreach materials they received as well as the outreach meeting by December 16, 2010. The Agency received written comments from, or on behalf of, ten SERs. Written comments also were received from the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA). (See appendix B).

7. LIST OF SMALL ENTITY REPRESENTATIVES

Eighteen SERs were selected for the Panel Process. The official SER list is as follows:

Atlantic Municipal Utilities
Atlantic, IA
Alan Bonderman

Bancroft Municipal Utilities
Bancroft, IA
Brian Hatten

Colstrip Energy LP
Boise, ID
Scott Siddoway

Central Iowa Power Cooperative*
Cedar Rapids, IA
Greg Gerdes and Rex Butler

Coon Rapids Municipal Utilities
Coon Rapids, Iowa

Corn Belt Power Cooperative*
Humboldt, IA
Michael Thatcher

Dalton Utilities
Dalton, GA

Geneseo Municipal Utilities*
Geneseo, IL
Tim Long

Holland Board of Public Works
Holland, MI
Daniel Nally

Jamestown Board of Public Utilities
Jamestown, NY
Steve Kulig

Marquette Board of Light & Power
Marquette, MI
Erik Booth

Montezuma Municipal Utilities
Montezuma, IA
Kevin Kundart

Muscatine Power & Water
Muscatine, IA
Donald Pauken

San Miguel Electric Cooperative, Inc.*
Joe Eutizi

Southern Illinois Power Cooperative*
Marion, IL
Leonard Hopkins

Tes Filer City Station Power Plant
Manistee, MI
Tondu Corporation
Houston, TX
James A. Ford

Texas Municipal Power Agency
Bryan, TX
Ken Babb

Wyandotte Municipal Services
Wyandotte, MI
James R. French

*SER for Panel on Clean Air Interstate Rule Federal Implementation Plan

Representatives of the NRECA, APPA, Edison Electric Institute (EEI), Hunton & Williams, and J.E. Cichanowicz, Inc. participated as viewers/technical backup that augmented the SERs and provided comment but did not act as SERs. Those representatives are as follows:

Bill Wemhoff
Sr. Principal, Environmental Policy
NRECA
Arlington, VA

Theresa Pugh
Director of Environmental Services
APPA
Washington, D.C.

Michael Rossler
Manager Environmental Programs
EEI
Washington, D.C.

Lee Zeugin
Attorney at Law
Hunton & Williams
Washington, D.C.

J. Edward Cichanowicz
J.E. Cichanowicz, Inc.
Saratoga, CA

8. SUMMARY OF INPUT FROM SMALL ENTITY REPRESENTATIVES

8.1 Number and Types of Entities Affected

The table in Chapter 5 of this report, which presents the small entities potentially affected by the Utility NESHAP, was provided to the SERs before the outreach meeting, and was discussed at the meeting. During the outreach meeting, SERs indicated that they believe more small entities than those EPA estimated will be impacted. With regard to municipalities, SERs pointed out that joint action agencies also could be small entities potentially impacted. For cooperatives, SERs indicated that in addition to small entity G&T cooperatives, there are small entity distribution cooperatives that own G&T entities that could be potentially impacted.

Written comments indicate that cooperatives are concerned that EPA's evaluation of the potential impacts on small entities fails to account for a large number of potentially affected small distribution cooperatives. Because the G&Ts are owned by the distribution cooperatives they serve, SERs believe that the Utility NESHAP will have a direct impact on all electric cooperatives generating and/or distributing coal-based power. NRECA provided a list of the 14 G&T cooperatives that own coal-fired generation and that NRECA believes qualify as small entities under the SBA size standards. NRECA's list includes cooperatives that NRECA believes meet the SBA size standards and were not on EPA's list, and omits some cooperatives that were on EPA's list and that NRECA believes do not meet the size standards. In addition, SERs believe that 559 distribution cooperatives also qualify as small entities.

8.2 MACT Floors and Variability

During the outreach meeting, SERs raised the following four issues with respect to determining MACT floors and assessing variability: (1) pollutant-by-pollutant ranking approach, (2) pollutants to be regulated, (3) floor determination methodology for existing units, and (4) assessment of emissions variability, including periods of startup and shutdown, and fuel, performance, and load variability. SERs believe that determining MACT floors on a pollutant-by-pollutant basis creates emission limits that are technically infeasible because the limits are based on the best performing units for each pollutant and not on the best performers on a unit or facility basis. SERs suggested that a facility-wide approach to determining the MACT floors should be used. An example of how a pollutant-by-pollutant approach could result in technical infeasibility with respect to CO and nitrogen oxides (NO_X) was discussed. SERs explained that minimizing CO to meet its limit could actually lead to an increase in NO_X emissions (i.e., de-tuning the boiler).

Written comments reiterated that the end result of determining a MACT floor for each HAP or HAP surrogate for each subcategory of sources is a set of MACT floors that do not represent the emission levels achieved by an actual, best-performing unit. Instead, they reflect the performance of a hypothetical, ideal unit that does not exist. SERs believe that this methodology for setting MACT floors is inconsistent with CAA section 112(d)(3) requirements. In addition, by focusing on one HAP at a time, SERs believe that the antagonistic effects a given HAP limit will have on other regulated pollutants are missed (e.g., production of CO during the combustion process is inversely related to NO_X production and, therefore, it may be difficult to meet a CO limit if NO_X reductions are also required). One SER explained that, in fact, using CO as a surrogate is a concern because of the inverse relationship between NO_X and CO.

In written comments, SERs stated their belief that the Utility NESHAP should be limited to mercury control only. EPA has not determined that emissions of other HAP in the quantities emitted are detrimental to human health or the environment. SERs support EPA's 2004 legal analysis of why it believed it only had authority to set MACT standards for mercury under section 112(d) of the CAA (see 69 FR 4659-61, January 30, 2004).

SERs commented during the outreach meeting that the MACT floor for existing units should be determined using the entire inventory of EGUs and not using only the units for which EPA has test data. SERs believe that basing the MACT floor on only those units for which there is data results in a floor value that is representative of the "best of the best" (i.e., based on the best performing units of the group of units estimated by EPA to be the best performers and, therefore, were required to conduct emissions tests). In written comments, SERs stated their belief that Congress never contemplated the situation where the amount of available data from a large source category or subcategory would require EPA to set MACT limits based on the performance of only one or two sources (as EPA did in the proposed NESHAP for major industrial, commercial, and institutional boilers and process heaters).

With respect to estimating variability associated with emissions of the best performing EGUs, during the outreach meeting, SERs asked that EPA consider establishing percent reduction limits (i.e., required emissions reduction between the EGU inlet and the stack) as an alternative to complying with an emissions limit (i.e., an emissions value at the stack). They believe that percent reduction limits would provide small entities flexibility in complying with the NESHAP in addition to providing a means of potentially accounting for variability. SERs expressed concern that periods of startup and shutdown could present problems with meeting PM, CO, and other emission limits. During these periods, the emissions tend to increase to levels that in some instances are far greater than emissions during normal operation. SERs commented that an approach that would aid small entity compliance by accounting for startup and shutdown periods would be to base emissions limits on a longer averaging time (e.g., 30-days or 12-months, as recommended in written comments from one SER) rather than basing limits on 3-run (hour) averages. Given the inherent variability in boiler performance, a longer averaging period, especially for CO, would prevent a single spike in emissions from causing a well performing unit to be in non-compliance.

SERs stated in written comments that in order for a standard to be achievable, it must be achievable under most adverse circumstances which can reasonably be expected to recur and, thus, the rule must account for all variability in HAP emissions. One SER pointed out that EPA was instructed by the court to consider the efficiency of control equipment but also non-technology factors that may influence the emissions of the best performing units. That SER also explained that three-day stack sampling provides a snapshot of a unit's HAP emissions and is not indicative or representative of the unit's emissions over longer periods of time. Thus, the SER stated that EPA must account for emissions variability in order to determine the level of performance achieved by the best performing units and inquired how EPA plans to modify the stack emissions to account for fuel, performance, and load variability. SERs restated their recommendation that the rule should include an either/or standard of percent reduction or emission limits to allow the source to comply with the least expensive or burdensome option. They pointed out that the composition of coal used at facilities can vary considerably due to dissimilarity in composition from different locations or layers in the mine, to the use of coal from more than one mine, and to the blending of various sources, types, or amounts of coal. One SER pointed out that, over the past six years, variation in their monthly composite coal sample from a single mine has ranged between 17 and 48 pounds of mercury per trillion Btu, and yearly averages have ranged between 24.5 and 31.9 pounds of mercury per trillion Btu. That SER recommended an emissions standard based on a 12-month rolling average due to the variability of mercury in fuel and the difficulty of measuring minute quantities of mercury. SERs representing cooperative entities believe that work practice standards are more appropriate during periods of startup, shutdown, and malfunction than are HAP emission limits based on long-term rolling averages.

One SER indicated that de minimis exemption is a regulatory option/small entity flexibility that EPA should consider.

8.3 Monitoring, Reporting, and Recordkeeping

During the outreach meeting, SERs made several observations in response to EPA's estimated costs for mercury and PM continuous emissions monitoring systems (CEMS). Based on their experiences, mercury CEMS are expensive and haven't worked well. One SER stated that the total capital investment for a mercury CEMS is close to double the cost estimated by EPA (i.e., $400,000–$500,000, rather than $260,000). A SER explained that their mercury CEMS worked for about one month and has presented numerous problems in the two and a half years since that time. For these reasons, SERs believe that mercury CEMS should not be a requirement of the Utility NESHAP. SERs stated that PM CEMS are not widely deployed within the utility sector. SERs expressed a concern regarding the ability of PM CEMS to operate properly in stacks containing moisture (i.e., EGUs with wet scrubbers). One SER suggested that requiring opacity monitoring and periodic emissions testing is more appropriate than requiring PM CEMS. Another SER stated that if PM CEMS are required by the Utility NESHAP, opacity monitoring requirements (i.e., continuous opacity monitors) of other Federal regulations should no longer apply.

In written comments, SERs recommended that monitoring, reporting, and recordkeeping requirements should be minimized and simplified to the maximum extent possible. One SER indicated that the use of PM as a surrogate for metal HAP is of concern because it would necessitate the use of PM monitoring technology which, according to the SER, is in its infancy and has not been proven to be reliable over varying load ranges. The SER stated that another problem regards the need to install PM monitors upstream of wet scrubbers rather than in the stack as is typical. Upstream installation will not account for the PM removal that occurs in the wet scrubber. Another SER recommended the use of opacity as an economical and proven indicator of good particulate emission controls over use of PM CEMS. They pointed out that PM CEMS offer no benefits to units that already have the Best Available Control Technology (BACT) installed and will already be below what the SER posits the PM limit may be.

8.4 Subcategorization

One SER commented during the outreach meeting that EPA should subcategorize lignite-fired EGUs from other coal-fired EGUs. The SER further commented that separate subcategories should be established for the two types of lignite-fired EGUs (i.e., North Dakota lignite and Gulf Coast lignite). The SER indicated that not only do lignite-fired EGUs differ from other coal-fired EGUs, but EGUs fired with the two types of lignite also have very different characteristics. SERs explained that blending of bituminous and sub-bituminous coals in EGUs is a common practice. An option mentioned to address the practice of coal blending is to establish separate subcategories for bituminous coal-fired EGUs, sub-bituminous coal-fired EGUs, and blended bituminous/sub-bituminous coal-fired EGUs. No subcategorization of bituminous, sub-bituminous, and blended bituminous/sub-bituminous coal-fired EGUs is another option mentioned during discussion of coal blending. SERs pointed out that consideration needs to be given to how EGUs that may move between subcategories, depending on the subcategories that are established, will be regulated and show compliance with the applicable standards. For example, if subcategories were established for bituminous coal-fired EGUs, sub-bituminous coal-fired EGUs, and blended bituminous/sub-bituminous coal-fired EGUs, a single unit could potentially burn 100 percent bituminous coal at times, 100 percent sub-bituminous coal at times, and a blend of bituminous and sub-bituminous coal at other times. Some SERs requested that EPA consider establishing a subcategory for combined heat and power (CHP) units that meet the definition of EGU (i.e., generate enough electricity). With regard to consideration of separate subcategories for base-load EGUs and peaking EGUs, SERs explained that the duty cycles for some coal-fired EGUs are not primarily base-load, as in the past, but may alternate between operating as base-load units and peaking units. Similar comments were not made with regard to consideration of base-load oil-fired EGUs and peaking oil-fired EGUs as separate subcategories.

In written comments, SERs encouraged the broad use of subcategories. They pointed out that in providing EPA discretion to create subcategories, section 112(d)(1) of the CAA does not restrict subcategorization to cases where the class, type or size factors affect HAP emissions. As an example, SERs explained that, under CAA section 111, EPA has subcategorized boilers on the basis of size (heat input) or the type of fuel burned (coal, oil or gas) and that these subcategorization decisions were based on feasibility and/or cost considerations, not on the level of emissions. One SER specifically indicated that subcategorization based on EGU size should be one of the approaches considered when proposing the rule. SERs indicate that coal rank has a significant effect on mercury and HCl emissions. In addition to recognizing the differences in the characteristics of the Gulf Coast lignite and the North Dakota lignite, SERs pointed out that the quality of coal in the Illinois basin varies considerably even within the basin. One SER stated that subcategories should be established for base-load EGUs and peaking EGUs. The SER supported subcategories based on whether an EGU burns Powder River Basin (PRB) coal, lignite, fuel oil, or other fuel types. The SER further stated that the ability to change subcategory with changes in fuel type will be important. Another SER recommended that wall-fired EGUs and tangentially-fired EGUs should be separate subcategories. The SER explained that tangentially-fired units have lower NO_X emission rates than wall-fired units. NO_X is not directly affected by the Utility NESHAP but CO may be used as a surrogate for organic HAP. Because NO_X and CO are inversely related, the SER further explained that the lower NO_X emissions provide an advantage to tangentially-fired units. SERs representing public power entities urged EPA to consider a separate subcategory for small non-profit electric providers if the Agency continues with enacting multiple large-scale regulations. One SER also stated that EPA should consider a co-firing subcategory for coal and biomass with emission limits somewhere between the units designed to burn coal and units designed to burn biomass. Addition of such a subcategory would offer an incentive to offset the combustion of coal with biomass.

8.5 Area Source Standards

During the SER Outreach meeting, SERs suggested that EPA establish separate emission standards for EGUs located at area sources of HAP and for EGUs located at major sources of HAP. SERs suggested that the standards for EGUs at area sources be based on GACT rather than MACT, as allowed under section 112(d)(5) of the CAA. Specifically, SERs recommended that EPA establish management practice standards for natural area source EGUs as well as synthetic area source EGUs. EPA estimates that there are approximately three natural area source EGUs and between 30 and 40 synthetic area source EGUs.

In written comments, SERs encouraged EPA to exercise its discretion and set separate standards for EGUs that qualify as area sources. They believe that separate standards would have the effect of lessening the regulatory burden on small entities.

8.6 Work Practice Standards

During the outreach meeting, SERs recommended that EPA establish work practice standards for major source EGUs. This recommendation was further detailed in written comments. SERs urged EPA to promulgate work practice standards as a replacement for emission limits to the fullest extent allowed. Specifically, SERs believe it is not feasible to prescribe or enforce an emission standard for control of a HAP emitted at or below the detection limit of the method that was used to collect and analyze HAP emissions (i.e., the uncertainty about the accuracy of a compliance measurement is as great as the measurement being reported). A number of HAP, including a large percentage of the dioxin/furan and non-dioxin organics measurements) from EGUs are emitted at or below detection limits. Therefore, in these instances, SERs believe that CAA section 112(h) allows the Administrator to promulgate a design, equipment, work practice, or operational standard.

8.7 Health Based Emission Limits

SERs commented during the outreach meeting that EPA should consider using its CAA section 112(d)(4) authority to set a health based emission limit (HBEL) for HCl based on its reference concentration for the entire EGU source category. In written comments, SERs stated that HBELs should be used to the maximum extent possible when facts support their use, such as for acid gas emissions (e.g., HCl, HF, Cl_2, HCN) from coal-fired EGUs.

8.8 Related Federal Rules

During the outreach meeting, SERs asked that EPA consider the impact of competing regulatory requirements and technologies when developing the Utility NESHAP. They expressed concern with how other regulatory actions would impact EGUs' emissions profiles and if those impacts would be accounted for when determining requirements of the NESHAP. Specifically, SERs questioned what the impact of controlling SO_2 and NO_X emissions as a result of complying with the Transport Rule will do to the level of CO emissions, given the NO_X-CO relationship (i.e., when NO_X emissions are reduced, CO emissions may increase). SERs commented that if CO emissions are, in fact, elevated in the future due to controlling NO_X emissions as required by the Transport Rule, those higher CO emissions won't be reflected in the Utility NESHAP emission limit calculations because those calculations will be based on current emissions data that don't reflect the potential future emissions profiles impacts of other regulatory requirements. The SERs are concerned with the degree to which multiple Federal rules may have cumulative impacts on small entities.

In written comments, SERs stated that EPA should consider the synergistic adverse impacts that the Utility NESHAP will have on small cooperatives in conjunction with the many other air-related rulemakings that are ongoing. They further explain that cooperatives will experience disproportionately higher costs due to their greater dependence on coal-fired generation and, being non-profit, all costs will have to be passed on to their consumer-owners. SERs representing public power entities estimated that anywhere from 30-50% of the remaining coal-fired power plants might decide to close those plants due to the many environmental regulations affecting the utility sector from 2014 to 2020. Taken one at a time, compliance with the various rules is possible on an economical basis. However, when the capital cost must be absorbed at once, one SER explained that small non-profit municipalities and their ratepayers will suffer economic hardships. Because municipalities do not generate profits for shareholders and the municipal rate is set at a level to cover the cost of service provided, increased costs cannot be offset by reducing profit margins and costs must be passed on to the end user. One SER requested that EPA coordinate the various new regulations to minimize their impact on facilities with minimal planning staff (e.g., the SER's facility has three environmental positions that are responsible for monitoring regulatory developments and planning to implement them, in addition to the day-to-day environmental responsibilities).

8.9 Potential Adverse Economic Impacts

SERs commented during the outreach meeting on a number of concerns they have with respect to small entities' ability to comply with the potential requirements of the Utility NESHAP. Those concerns included (1) market implications, (2) labor and materials shortages, (3) competing regulatory interests, (4) financial constraints, (5) the ability to get and repay the necessary capital, (6) competing against large companies for loans, engineering services, equipment vendor services, emissions testing contractors, etc., (7) the lack of infrastructure, (8) physical constraints (i.e., footprint availability), (9) the lack of necessary implementation time (SERs estimated that 5 to 8 years will be necessary for planning and engineering, financing, delivery and installation, emissions testing, etc.), and (10) a potential permitting delay caused by entities making other improvements (e.g., energy efficiency improvements) at the same time they comply with the Utility NESHAP that trigger New Source Review (NSR). Based on these concerns, as well as the overall concern that compliance with the Utility NESHAP will complicate the SERs' ability to finance and plan ahead for meeting other future rules impacting EGUs, SERs believe that accommodations for small entities are warranted. With respect to dates associated with the NESHAP, SERs inquired as to EPA's authority to (1) move the effective date of the standards, (2) determine when implementation begins, (3) allow a phase-in of compliance, and (4) streamline the process for petitioning for a fourth year for purposes of complying with the standards.

SERs asked that EPA consider the implications of EGU reliability versus compliance with the Utility NESHAP when establishing the rule's requirements. To comply, each EGU will be required to go offline for a period (or several periods) of time (i.e., "outage"). SERs commented that those offline periods may not correspond with a scheduled outage and explained that each outage has to be approved and may not be allowed for the time period requested. In written comments, SERs representing public power entities stated that there will be significant constraint issues with the electric grid if EPA proceeds with a 3-year compliance schedule. EGUs will have to compete for an outage schedule and the Utility NESHAP time constraints will not be flexible enough to take into account the timeframe needed so that each unit can go down and still satisfy the demands for power. One SER explained that during an outage his entity must continue purchasing power to supply system load but will not be receiving revenues from supplying that power. Thus, the entity will not only incur the cost of the pollution control equipment, but also experience lost revenues. Another SER recommended that any new pollution control requirements should be designed to utilize existing equipment to the greatest extent possible. The SER indicated that the lack of back-up generation is a particular concern for small entities. If the addition of a new pollution control device requires electricity generation to end for many months, the member municipalities would lose their primary source of electric power for that entire time.

SERs expressed concern that, depending on the type and stringency of requirements, the regulations could be so expensive that they cause extensive plant retirements and job losses. In written comments, SERs representing cooperative entities explained that because the G&T cooperatives are owned by the distribution cooperatives they serve, there are no third party shareholders who could help share the costs of compliance. All additional costs borne by the cooperative (and paid for by the distribution cooperative member-owners) affect the financial well-being of the G&T cooperative. Thus, the notion that passing through regulatory compliance costs to customers will somehow avoid or mitigate their impact does not apply to consumer-owned cooperatives. SERs representing public power entities explained in their written comments that increased costs cannot be offset by reducing profit margins and costs must be passed on to the end user. One SER indicated that capital investment would be recovered through retail rates, and that typically rate adjustments take about six months. SERs stated that in addition to residential ratepayers, small businesses (e.g., grocery stores, retailers, locally owned gas stations) would endure hardships from an increase in electric rates in an already difficult economic climate.

In written comments, SERs stated that certain EGUs may have site unit-specific special considerations for which the potential negative impacts must be assessed and that must be addressed in a final rule (e.g., through providing alternative compliance methods). For example, specific units may not have the physical space to add the required control equipment or, for some sources, fuel switching may not be a reasonable or practical alternative to meeting emission limits. One SER suggested that EGUs at sites hampered by physical site constraints may need a limit higher than MACT (i.e., a limit that can be met using a control device that would fit in the physical constraints of the site). SERs believe that small entities with few units should be given additional time to comply with new requirements in order to account for their disadvantage in competing with large electric generating providers for equipment and skilled labor resources in a severely tight compliance timeframe. SERs believe that the most competitive pricing and attention will go to the large-scale accounts due to the limited number of manufacturers. In his written comments, one SER estimated that it will take a minimum of one year to obtain financing and suggested that the U.S. Department of Agriculture's Rural Utilities Service (RUS) electric loan policy be changed to allow loans for coal-fired projects to meet environmental regulations. Another SER estimated that six months will be needed to obtain funding through municipal bonds once the project cost is known. One SER recommended that small entities be given an additional three years to install the required emission controls. Another SER recommended that consideration be given to an approach that requires the largest emitters to install control technology first, followed by a second phase for moderate emitters, and, lastly, followed by a third phase for the lowest emitters. One SER recently investigated converting a hot side electrostatic precipitator (ESP) to a fabric filter, and their analysis concluded that it would take a minimum of 40 months to complete the project (not accounting for the need to compete for resources).

One SER pointed out that, with respect to fuel switching, sources without transportation infrastructure to unload coal via railroad or that are not on a navigable waterway are at a significant disadvantage as compared to sources that receive coal via railroad or river/ocean barge. In addition, it is unknown whether a replacement fuel could be used without a major modification of a boiler that was built to handle a specific coal rank. The SER recommended that the MACT standard not be finalized in a manner that would effectively require a fuel change (blending or completely), especially for mine mouth coal electric generating stations.

One SER stated that energy optimization should be incorporated in the Utility NESHAP. EPA should include guidelines and a project specific list of process changes and modifications that will not trigger NSR. The SER further explained that the ambiguity of what triggers NSR and the litigious atmosphere surrounding boiler upgrades provides a disincentive for utility efficiency improvements.

8.10 Concerns with the Small Business Advocacy Review Process

In written comments, SERs stated that they do not believe they were provided the opportunity for effective participation in the Federal regulatory process as required by

SBREFA. Specifically, SERs indicated that they were not provided descriptions of significant alternatives to the proposed rule, differing compliance or reporting requirements or timetables that take into account the resources available to small entities, and the clarification, consolidation, or simplification of compliance and reporting requirements for small entities. SERs further indicated that there was no pre-meeting to go over information on the rule, there was only one outreach meeting, and SERs were only provided 14 days to prepare written comments. Thus, the highly abbreviated small business review panel prevents small entities from having the meaningful advisory role contemplated by SBREFA. SERs requested that EPA schedule additional panel meetings once the Agency has progressed further in its rulemaking preparation. One SER indicated that EPA should consider starting over with the SBREFA process. Another SER recommended that EPA request an extension from the court deadline to allow time to (1) adequately analyze lessons learned in the Boiler MACT rule development process, (2) thoroughly analyze the emissions data, (3) continue to meet with utility industry representatives, and (4) consider the range of possible emission control options that would allow for implementation to take place such that the integrity of the Grid, the national economy, and national security will be protected.

9. PANEL FINDINGS AND DISCUSSION

9.1 Number and Types of Entities Affected

In general, SERs believe that more small entities than those estimated by EPA will be impacted by the Utility NESHAP. SERs representing public power entities made the point that joint action agencies could be small entities potentially impacted by the Utility NESHAP. SERs representing cooperatives pointed out that a large number of small distribution cooperatives that own generation cooperatives also could be potentially impacted by the NESHAP.

With regard to the SERs' comment that joint action agencies also could be small entities potentially impacted, the Panel notes that two joint action agencies, Municipal Energy Agency of Nebraska and Southern Minnesota Municipal Power Agency, are included on the list of potentially impacted small entities. The RFA guidance directs EPA to estimate direct impacts at the highest level of ownership (i.e., holding company) rather than at the subsidiaries/member level. Even if impacts were estimated at the member level for these two organizations, the potential impacts would be far less because the overall impacts on each joint action agency would be divided among the total number of members.

Regarding cooperatives, SERs indicated that there are small entity distribution cooperatives that own G&T entities that could be potentially impacted. The Panel notes that because transmission processes will not be regulated by the Utility NESHAP, impacts to entities that own those processes cannot be accounted for in the small entity analysis. Thus, if a small entity distribution cooperative owns transmission processes, the impacts for the NESHAP are indirect in nature and not accounted for in the small entity analysis. The Panel acknowledges that small entity distribution cooperatives that own generation processes would be impacted in some way by the Utility NESHAP because generation processes will be regulated by the standards, but the extent to which small entity distribution cooperatives would be impacted is unclear without more detailed information on these entities. It should be noted that some small entity distribution cooperatives own small entity generation cooperatives, but other small entity distribution cooperatives own generation cooperatives that are not small entities, or other distribution cooperatives that are not small entities own small entity generation cooperatives.

For an estimate of the type and number of small entities to which the proposed rule will apply, see Section 5.

9.2 MACT Floors and Variability

SERs raised four issues with respect to determining MACT floors and assessing variability: (1) pollutant-by-pollutant ranking approach, (2) pollutants to be regulated, (3) floor determination methodology for existing units, and (4) assessment of emissions variability, including periods of startup and shutdown, and fuel, performance, and load variability. We lay out our recommendations for each of these issues in succession below.

SERs stated that the end result of determining a MACT floor for each HAP or HAP surrogate (a pollutant-by-pollutant approach) for each subcategory of sources is a set of MACT floors that do not represent the emission levels achieved by an actual, best-performing EGU. SERs believe that this methodology for setting MACT floors is inconsistent with the requirements of CAA section 112(d)(3).

Panel Recommendations

EPA recommendation: Consistent with EPA's legal interpretation, EPA panel members recommend that the Agency use the pollutant-by-pollutant approach for determining MACT standards for each HAP or HAP surrogate, while taking into account potential direct conflicts between pollution control technologies

As noted above, there are concerns with respect to the suggestion that MACT floors should be established using a facility-wide approach. Determining floors based on a facility-wide approach would lead to least common denominator floors – that is floors reflecting mediocre or no control, rather than performance which, for existing sources, is the average of what the best performing sources have achieved. For example, if the best performing 12 percent of facilities for HAP metals did not control organics as well as a different 12 percent of facilities, the floor for organics and metals would end up not reflecting best performance. This fact pattern has come up in every rule where EPA investigated a facility-wide approach. See, e.g. 75 FR at 54999 (Sept. 10, 2010). Thus, utilizing the single-facility theory proffered by the stakeholders would result in EPA setting the standards at levels that would, for some pollutants, actually be based on emissions limitations achieved by the *worst*-performing unit, rather than the *best*-performing unit, as required by the statute. Moreover, a single-facility approach would require EPA to make value judgments as to which pollutant reductions are most critical in working to identify the single facility that reduces emissions of HAP on an overall best-performing basis.

OMB and SBA recommendation: OMB and SBA recommend that in the proposed rule, EPA seek comment on reasonable alternative approaches to setting the MACT floor, which account for achievement in practice for control of all HAP.

SERs stated their belief that the Utility NESHAP should be limited to mercury control only. They explained that EPA has not determined that emissions of other HAP in the quantities emitted are detrimental to human health or the environment. SERs continue to support EPA's 2004 legal analysis that stated EPA believed it only had authority to set MACT standards for mercury under CAA section 112(d).

Panel Recommendations

EPA recommendation: As to the comment that EPA should only regulate mercury from coal-fired EGUs and nickel from oil-fired EGUs consistent with the reasoning in the proposed NESHAP for these sources that was published on January 30, 2004, EPA panel members note that the Agency never finalized that proposed interpretation, and the Agency has determined that it must establish CAA section 112(d) standards for all HAP emitted from major source EGUs consistent with the statute and case law from the Court of Appeals for the D.C. Circuit. Specifically, CAA section 112(n)(1)(A) requires EPA to regulate EGUs "under this section [112]" if the Agency determines that regulation is appropriate and necessary. Sources are regulated under CAA section 112 consistent with the requirements of CAA sections 112(d) and (f). The D.C. Circuit has stated, on more than one occasion, that EPA must establish MACT standards for each listed HAP emitted by major sources, the most recent pronouncement coming three years after the proposed NESHAP for EGUs. See Sierra Club v. EPA, 479 F.3d 875, 883 (D.C. Cir. 2007). ("EPA has a 'clear statutory obligation to set emission standards for each listed HAP,' which does not allow it to 'avoid setting standards for HAPs not controlled with technology.'" quoting Nat'l Lime Ass'n v. EPA, 233 F.3d 625, 634 (D.C. Cir. 2000)); see also Natural Resources Defense Council v. EPA, 489 F.3d 1364, 1371 (D.C. Cir. 2007) (affirming that EPA must establish emission standards for listed HAP emitted from a category, citing Sierra Club and National Lime). For these reasons, EPA rejects the proposed interpretation set forth in the 2004 proposed rule.

OMB and SBA recommendation: OMB and SBA recommend that in the proposed rule, EPA seek comment on the specific elements of the 2004 legal analysis and how subsequent court decisions affect that 2004 legal analysis.

Panel Recommendation: The Panel recommends that the analysis of impacts be able to distinguish the marginal costs and benefits of each required control technology, in order for the public to distinguish the impacts of regulating mercury from the impacts of regulating other HAPs. It should be noted that EPA cannot, at this point, estimate monetized benefits for HAP reductions other than Hg.

In addition, by focusing on one HAP at a time, SERs believe that the antagonistic effects a given HAP limit will have on other regulated pollutants are missed. Because production of CO during the combustion process is inversely related to NO_X production, it may be difficult to meet a CO limit if NO_X reductions also are required.

Panel Recommendation: The Panel recommends that the Agency investigate other potential surrogate pollutants for organic HAP (e.g., PAH, formaldehyde). The SERs' example of how a pollutant-by-pollutant approach could result in technical infeasibility with respect to CO and NO_X may argue against using CO as the surrogate pollutant for organic HAP.

SERs commented that the MACT floor for existing units should be determined using the entire inventory of EGUs and not using only the units for which EPA has test data.

Panel Recommendations

EPA recommendation: The CAA requires the MACT floor for existing sources be based on the best performing sources. Thus, EPA must be able to show that the best performing units are in fact used to establish the MACT floor. To use the entire inventory of EGUs as the basis for determining the average of the best performing 12 percent of units, EPA must be confident that the EGUs for which data are available are the best performers. EPA panel members recommend that the Agency establish the MACT floors using all the available ICR data that was received to the maximum extent possible consistent with the CAA requirements.

OMB and SBA recommendations: OMB and SBA recommend that EPA establish MACT standards that minimize the burden on small businesses. OMB and SBA also recommend that EPA consider, and present for comment, MACT floors based on the best performing 12 percent, rather than the best 12 percent of the data EPA collected. If EPA proposed the latter, OMB and SBA recommend that they clearly explain why the subset of sources for which they have data is representative of the entire set of sources.

SERs asked that EPA consider establishing percent reduction limits as an alternative to complying with an emissions limit as a means of providing small entities flexibility in complying with the NESHAP in addition to providing a means of potentially accounting for variability. SERs expressed concern that periods of startup and shutdown could present problems with meeting emission limits and suggested that the emissions limits be based on a longer averaging time rather than basing limits on 3-run averages. SERs stated that the three-day stack sampling required by EPA's ICR provides a snapshot of a unit's HAP emissions and is not indicative or representative of the unit's emissions over longer periods of time. SERs pointed out that a critical question is how EPA plans to modify the stack emissions reported during the ICR to account for fuel, performance, and load variability. One SER suggested that use of a longer-term rolling average (i.e., a 12-month minimum rolling average) is necessary in order to account for varying levels of mercury in fuel. Additionally, one SER indicated that a *de minimis* exemption is a regulatory option/small entity flexibility that EPA should consider.

Panel Recommendations

EPA recommendations: EPA is limited in its ability to establish percent reduction limits as an alternative to complying with an emissions limit. Even assuming that EPA can establish percent reduction standards under CAA section 112, to establish such standards, emissions data for the inlet to the EGU and for the stack are necessary. At this time, EPA does not have such data. EPA panel members recommend that the Agency consider the inclusion of percent reduction standards given the legal constraints and the lack of data necessary to establish such standards. Regarding the SERs' concerns with meeting emissions limits during periods of startup and shutdown, EPA panel members recommend that the Agency base the proposed emission limits on reasonable averaging times where appropriate. In determining reasonable averaging times, EPA panel members recommend that in addition to considering performance during periods of startup and shutdown, the Agency also consider fuel and load variability. In addition, EPA panel members recommend that the Agency use all data gathered through the ICR for EGUs that comprise the MACT floor, to the maximum extent possible consistent with the CAA requirements and as appropriate, in order to account for fuel, performance, and load variability. With regard to one SER's request that a *de minimis* exemption be considered, EPA must establish standards for all HAP emitted from major sources consistent with CAA section 112(d) and case law from the U.S. Court of Appeals for the D.C. Circuit. See Sierra Club v. EPA, 479 F.3d 875, 883 (D.C. Cir. 2007) ("EPA has a 'clear statutory obligation to set emission standards for each listed HAP,' which does not allow it to 'avoid setting standards for HAPs not controlled with technology.'" quoting Nat'l Lime Ass'n v. EPA, 233 F.3d 625, 634 (D.C. Cir. 2000)); see also Natural Resources Defense Council v. EPA, 489 F.3d 1364, 1371 (D.C. Cir. 2007) (affirming that EPA must establish emission standards for listed HAP emitted from a category, citing Sierra Club and National Lime).

Panel recommendations: The Panel recommends that EPA propose provisions for emissions averaging between units at a facility and long averaging times to address startup, shutdown, and fuel variability for the proposed emissions limit and, further, that the Agency solicit comment on an appropriate averaging time. The Panel recommends that EPA consider fuel variability when deriving the emissions standards. The panel members recommend that the Agency evaluate whether establishing work practice requirements during periods of startup and shutdown would be consistent with CAA section 112(h) and investigate whether there are technical bases for establishing separate standards (e.g., work practices or subcategorization) for EGUs below a certain size and what that size threshold is.

9.3 Monitoring, Reporting, and Recordkeeping

In general, SERs recommended that monitoring, reporting, and recordkeeping requirements should be minimized and simplified to the maximum extent possible. SERs specifically expressed concern with potential requirements under the Utility NESHAP that CEMS be used.

Panel Recommendations

EPA recommendations: EPA panel members recommend that the Agency consider proposing alternative monitoring approaches (e.g., parameter monitoring in lieu of requiring the use of mercury CEMS, sorbent traps, periodic stack testing, etc.) and consider requiring PM CEMS only for the largest EGUs or allow use of PM CEMS as an alternative to conducting opacity monitoring and periodic emissions testing. With respect to SERs' suggestion that if PM CEMS are required by the Utility NESHAP, opacity monitoring requirements of other Federal regulations should no longer apply, EPA panel members recommend that the Agency consider the available alternatives and options to the current opacity provisions.

OMB recommendations: OMB recommends EPA propose alternative monitoring approaches (e.g., parameter monitoring in lieu of requiring the use of mercury CEMS, sorbent traps, periodic stack testing) for small entities and that EPA propose PM CEMS only for the largest EGUs or propose allowing use of PM CEMS as an alternative to conducting opacity monitoring and periodic emissions testing.

SBA recommendations: SBA agrees that EPA should consider relevant factors identified by the SERs in developing this rulemaking, but it does not believe that the Panel has sufficient information to make recommendations beyond EPA's existing obligations under the RFA or Paperwork Reduction Act. SBA agrees that these are flexibilities worthy of consideration, and perhaps proposal, but without information necessary to evaluate specific regulatory alternatives or the impacts of those decisions on particular small entities or small entities in general, SBA believes that the Panel can make no recommendations as to what specific regulatory options would "accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities."

9.4 Subcategorization

In general, SERs encouraged the broad use of subcategories. SERs commented that EPA should consider subcategorizing EGUs based on fuel type, boiler type, duty cycle, and size. Some SERs requested that EPA consider establishing a subcategory for combined heat and power (CHP) units that meet the definition of EGU (i.e., generate enough electricity). SERs explained that the duty cycles for some coal-fired EGUs are not primarily base-load, as in the past, but may alternate between operating as base-load units and peaking units. Similar comments were not made with regard to consideration of base-load oil-fired EGUs and peaking oil-fired EGUs as separate subcategories.

Panel Recommendations

EPA recommendations: EPA recognizes subcategorization may be necessary and we will consider whether subcategorization is reasonable in light of the data and other information obtained in response to the ICR to the utility industry and the information from the SERs. SERs recommended that EPA consider adopting the following subcategories for EGUs:

- Fuel type
    - ► North Dakota lignite
    - ► Gulf Coast lignite
    - ► Bituminous coal
    - ► Sub-bituminous coal
    - ► Blended bituminous/sub-bituminous coal

    - ► Powder River Basin coal
    - ► Illinois Basin coal
- Boiler design
    - ► Units designed to burn coal
    - ► Units designed to burn oil
    - ► IGCC units
    - ► CHP units
    - ► Units designed to burn multiple fuels
- Unit type
    - ► Fluidized bed
    - ► Pulverized coal
    - ► Wall-fired
    - ► Tangentially-fired
- Duty cycle
    - ► Base-load oil-fired units
    - ► Peaking oil-fired units
    - ► Base-load coal-fired units
    - ► Coal-fired units that alternate operating as base-load and peaking
- Boiler class
    - ► Small entity non-profit providers

<u>EPA and OMB recommendations</u>: EPA panel members and OMB acknowledge that it may not be practicable to adopt all of the proposed subcategories, as there may be substantial overlap between the groups. EPA panel members and OMB recommend that EPA consider these subcategories and adopt a set of standards that is consistent with the CAA and which effectively reduces burden on small entities.

<u>SBA recommendations</u>: SBA agrees that EPA should consider various subcategorization options in developing this rulemaking, but it does not believe that the Panel has sufficient information to recommend a particular subcategorization option that would minimize the significant economic impact of the proposed rule on small entities. While a large number of subcategories may serve to establish standards that minimize the economic impacts on some particular small entities, it could also disadvantage small entities that would otherwise be among the best performing 12 percent of a larger subcategory.

9.5 Area Source Standards

SERs suggested that EPA establish separate emission standards for EGUs located at area sources of HAP and that the standards be based on GACT as allowed under section 112(d)(5) of the CAA. Specifically, SERs recommended that EPA establish management practice standards for natural area source EGUs as well as synthetic area source EGUs.

<u>Panel Recommendations</u>

<u>EPA recommendations</u>: EPA panel members recommend that the Agency consider a regulatory approach for EGUs at area sources of HAP based on GACT. Further, EPA panel

members recommend that the Agency consider establishing management practices for area source EGUs pursuant to CAA section 112(d)(5).

OMB recommendations: OMB recommends that EPA propose a regulatory approach for EGUs at area sources of HAP based on GACT and propose management practices for area source EGUs.

SBA recommendations: SBA agrees that EPA should consider the use of its authority to establish area sources standards for natural and synthetic area sources to the maximum extent permitted by statute, but does not believe that the Panel has sufficient information to recommend a particular regulatory option that would minimize the significant economic impact of the proposed rule on small entities.

9.6 Work Practice Standards

SERs recommended that EPA establish work practice standards for major source EGUs. A work practice standard, instead of MACT emission limits, may be proposed if it can be justified under section 112(h) of the CAA that it is not feasible to prescribe or enforce an emission standard (i.e., the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations). Specifically, SERs believe it is not feasible to prescribe or enforce an emission standard for control of a HAP emitted at or below the detection limit of the method that was used to collect and analyze HAP emissions. A number of HAP, including a large percentage of the dioxin/furan and non-dioxin organics measurements, are emitted at or below detection limits.

Panel Recommendations

EPA and OMB recommendation: EPA panel members and OMB recommend that the Agency evaluate the availability of work practice standards pursuant to CAA section 112(h), in particular with regards to HAP that are emitted at or below the detection limit.

SBA recommendation: SBA recommends that EPA propose work practices standards pursuant to CAA section 112(h) to the maximum extent permitted by statute. However, the Panel does not have sufficient information to specify which work practices standards can be proposed.

9.7 Health Based Emission Limits

SERs commented that HBELs should be used to the maximum extent possible when facts support their use. Specifically, SERs encouraged EPA to use its CAA section 112(d)(4) authority to set a HBEL for HCl based on its reference concentration for the entire EGU source category.

Panel Recommendations

EPA recommendation: EPA panel members recommend that the Administrator consider her discretionary authority to propose a HBEL for acid gas HAP emissions as a regulatory flexibility option.

OMB and SBA recommendations: OMB and SBA recommend that in the proposed rule, EPA co-propose and seek comment on an HBEL for HAPs to the maximum extent permitted by statute, including, but not limited to, the acid gas HAP. OMB and SBA recommend that in the proposal EPA explain their method for deriving these limits, along with sample calculations.

9.8 Related Federal Rules

SERs asked that EPA consider the impact of competing regulatory requirements and technologies when developing the Utility NESHAP. EPA is currently working on revisions to the PM, SO_2, and NO_X emissions limit in subpart Da. Sources subject to the NSPS would also be subject to the Utility NESHAP because those rules regulate sources of HAP whereas the NSPS does not.

EPA issued a final rule that establishes thresholds for GHG emissions that define when permits under the New Source Review PSD and title V Operating Permit programs are required for new and existing industrial facilities (the Tailoring Rule). Beginning in January 2011, large industrial sources, including power plants, became subject to permitting requirements for their GHG emissions.

On December 23, 2010, EPA announced that it entered into a settlement agreement to issue rules that will address GHG emissions from fossil fuel-fired power plants. The rules would establish NSPS for new and modified EGUs and emission guidelines for existing EGUs. Under the agreement, EPA commits to issuing proposed regulations by July 26, 2011 and final regulations by May 26, 2012.

SERs expressed concern regarding what the impact of controlling SO_2 and NO_X emissions as a result of complying with the Transport Rule will do to the level of CO emissions. The Transport Rule, as proposed, would require 31 states and D.C. to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states. Specifically, the proposal would require reductions in SO_2 and NO_X emissions that cross state lines. The Transport Rule is expected to be finalized in late Spring 2011 and, to the extent that EGUs are located in the final set of states or D.C., they would be subject to the Transport Rule.

Based on the findings from EPA's multi-year study of the Steam Electric Power Generating industry, EPA plans to revise the current effluent guidelines that apply to steam electric power plants. Revised effluent guidelines will be proposed in July 2012 and finalized in January 2014.

As required by section 316(b) of the CWA, EPA established best technology available standards to minimize adverse environmental impacts from cooling water intake structures. In developing these standards, EPA divided its effort into three rulemaking phases. Phase I standards, for new EGU plants using cooling water, were finalized in June 2003. Phases II and III standards, which address existing EGU plants that use cooling water, were promulgated in July 2004 and June 2006, respectively. Both regulations were challenged. Several provisions of the Phase II rule were remanded and EPA suspended most of the rule in response to the remand. EPA requested, and was granted, a partial remand of the Phase III rule. EPA signed a settlement agreement that requires regulations for Phase II and III facilities to be proposed by March 14, 2011, and promulgated by July 27, 2012.

In June 2010, EPA proposed national rules for the management of coal ash, which are residues from the combustion of coal in power plants that are captured by pollution control technologies, like scrubbers. EGUs will be subject to these coal ash specific regulations when they are issued.

Panel Recommendations

SBA recommendations: SBA agrees that EPA should consider relevant factors identified by the SERs in development of this rulemaking, including the extent to which other recently proposed or finalized regulatory obligations imposed by EPA will impact small entities or make compliance with this rulemaking more difficult. However, SBA does not believe that the Panel has information necessary make recommendations beyond a restatement of EPA's existing obligations or to evaluate specific regulatory decisions and the impacts of those decisions on particular small entities or small entities in general. Therefore, SBA believes that the Panel can make no recommendations as to what specific regulatory options would "accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities."

Panel recommendations: Although the requirements of section 112 of the CAA direct EPA to establish NESHAP for both major and area sources of HAP and prescribe the processes by which the standards are developed, the Panel recommends that the Agency consider the various flexibilities within its discretion in developing the proposed standards. The Panel recommends that the Agency investigate other potential surrogate pollutants for organic HAP in lieu of CO, given the NO_X-CO relationship (i.e., when NO_X emissions are reduced, CO emissions may increase). In developing the NESHAP for EGUs, the Panel recommends that the Agency avoid duplicating requirements to the fullest extent possible in order to minimize unnecessary costs.

9.9 Potential Adverse Economic Impacts

SERs commented on a number of concerns they have with respect to small entities' ability to comply with the potential requirements of the Utility NESHAP. SERs inquired as to EPA's authority to (1) move the effective date of the standards, (2) determine when implementation begins, (3) allow a phase-in of compliance, and (4) streamline the process for petitioning for a fourth year for purposes of complying with the standards. SERs asked that EPA consider the implications of EGU reliability versus compliance with the Utility NESHAP when establishing the rule's requirements. SERs expressed concern that, depending on the type and stringency of requirements, the regulations could be so expensive that they cause extensive plant retirements and job losses.

Panel Recommendations

SBA recommendation: SBA recommends that EPA propose a streamlined process for granting a fourth year, including aiding small entities in gathering the information necessary to support such a petition, and recommends that EPA develop, in consultation with the Department of Defense and small entities affected by this rule, to develop the information necessary to support a recommendation under section 112(i)(4) of the CAA for consideration by the President.

Panel recommendations: The Panel recommends that the Agency weigh the potential burden of compliance requirements and consider various options for all regulated entities, especially small entities. With respect to dates, EPA does not have the authority to move the effective date of the standards (see CAA section 112(d)(10)), to initially provide more than three years for compliance (see CAA section112(i)), or to allow a phase-in of compliance. The Panel recommends that the Agency investigate the potential for streamlining the process for petitioning for a fourth year for purposes of compliance with the standards and consider the need to invoke the national security exemption under section 112(i)(4) of the CAA. Additionally, the Panel recommends that EPA seek comment in the proposed rule on the potential adverse economic impacts of the rule for small entities and recommendations for mitigating or eliminating these adverse economic impacts on small entities.

9.10 Concerns with the Small Business Advocacy Review Process

SERs stated that they do not believe they were provided the opportunity for effective participation in the Federal regulatory process as required by SBREFA. SERs indicated that they were not provided descriptions of significant alternatives to the proposed rule, differing compliance or reporting requirements or timetables that take into account the resources available to small entities. SERs further indicated that there was no pre-meeting to go over information on the rule, there was only one outreach meeting, and SERs were only provided 14 days to prepare written comments. SERs had various suggestions including that EPA schedule additional panel meetings once the Agency has progressed further in its rulemaking preparation, that EPA consider starting over with the SBREFA process, and that EPA request an extension to allow time to (1) adequately analyze lessons learned in the Boiler MACT rule development process, (2) thoroughly analyze the emissions data, (3) continue to meet with utility industry representatives, and (4) consider the range of possible emission control options that would allow for implementation to take place such that the integrity of the Grid, the national economy, and national security will be protected.

Panel Recommendations

EPA recommendation: EPA appreciates the SERs' concerns, but believes that it has fulfilled its statutory obligations under SBREFA and has afforded SERs sufficient opportunity to suggest regulatory alternatives, and thus, makes no recommendations to address these concerns. The time constraints of the small business advocacy review process with respect to the Utility NESHAP were explained at the beginning of the process. That is, due to the regulatory schedule there could only be one SER outreach meeting. The nature of the information to be provided was also outlined to the SERs at the start of the process. EPA believes that it has provided sufficient information to allow SERs to make suggestions concerning regulatory alternatives (e.g., regarding subcategories, HAP and HAP surrogates, monitoring requirements, control technologies potentially required to meet standards, CAA authorities to establish health-based emission limits and work practice standards) as part of the small business advocacy review process, and the SERs have in fact made many productive suggestions EPA will seriously consider as part of the rulemaking process.

OMB recommendation: Although OMB understands the time constraints imposed on this rulemaking process, we recommend that once EPA has drafted a set of emissions limits for EGUs, they convene another meeting with the SERs to gather insight on the feasibility and achievability of those limits for small entities. To the extent feasible, we recommend this meeting take place before the proposal is issued.

SBA recommendations: SBA agrees with the concerns raised by the SERs in their comments about the adequacy of the information provided to the Panel and the SERs and about the schedule for the Panel. SBA believes that more time is necessary for EPA to develop regulatory options and to share them with the SERs, so that the SERs could provide a more informed comment and better inform the Panel's recommendations.

SBA recommends that EPA request an extension of the regulatory deadlines imposed by the consent decree. The extension should provide enough time for EPA to:

- Analyze fully the results of the ICR and other data necessary to understand the emissions characteristics of the regulated entities;
- Develop a robust range of specific regulatory options;
- Consult with the SERs and provide an additional opportunity for the SERs to provide input on the regulatory options; and
- Allow for the full interagency review required by Executive Order 12866 and 13563.

Appendix A

List of Materials EPA Shared With SERs
(November 2010)

- PowerPoint Presentation entitled "Rulemaking for Hazardous Air Pollutants from Coal-and Oil-Fired Electric Utility Steam Generating Units" including:
    - Background
    - Project history
    - Section 112 overview
    - Constraints on rulemaking
    - Affected facilities
    - Data
    - Rulemaking options under consideration
    - Potential control technologies and estimated costs
    - Applicable small entity definitions
    - Small entities potentially subject to regulation
    - Questions for SERs

Appendix B

Questions for SERs

Directed Questions for SERs

<u>Affected Entities</u>

1. Is EPA's list of potentially affected small entities on slide A-4 of this presentation accurate? If not, do you have suggested additions or deletions? Could you briefly explain the reason for each addition or deletion.

<u>Firm Characteristics</u>

1. How many units do you have in your facility or facilities?
2. What is the capacity of your installed units?
3. What duty cycles do they run?

<u>Existing Standards</u>

General:

1. What Federal/State/local standards are your EGUs currently subject to?
2. What compliance requirements are associated with the other standards that apply to your EGU?
3. What emissions control technologies do you have installed at your facilities? Under what regulatory requirements are they installed? What did they cost to install? To operate?

Recordkeeping and Reporting:

1. What recordkeeping and reporting requirements are you subject to under other standards that apply to your EGU?
2. Are there recordkeeping and reporting alternatives that would simplify the requirements?

Monitoring:

1. Do you employ any monitors, for emissions or process parameters, to monitor the operation of your EGU?
2. What type of monitors and how many?
3. What were the capital costs and what are annual costs for each monitor?
4. Are these monitors in place for environmental regulatory reasons, insurance reasons, or other reasons?
5. Did you provide any of the monitoring data to the Agency during the recent Information Collection Request on Utility Boilers or another information collection request?

6. If your EGU is subject to emission limits, are there alternatives to monitoring emissions or stack testing that would be less costly to demonstrate compliance and, if so, how much less costly are the alternatives?

Energy Efficiency:

1. Do you employ measures to ensure that your EGU operates in an energy efficient manner?
2. What are the energy efficient measures you employ?
3. Are these measures a result of regulatory requirements, initiated voluntarily, or employed for other reasons?
4. What are the estimated emissions reductions associated with the energy efficient measures?
5. What are the costs of implementing the energy efficient measures?

<u>Regulatory Alternatives</u>

General:

1. What types of subcategories based on class, type, or size do you think EPA should consider and why?
2. What surrogate standards do you think are appropriate?
3. What means of determining variability do you think EPA should consider?

Work Practice Standards:

1. Which subset(s) of HAP from EGUs, if any, do you think would meet the CAA section 112(h) requirements for establishing work practice standards in lieu of emission limits and what is the basis for your assertion?
2. What work practice standards are available to you?
3. What work practice standards would you consider to be reasonable alternatives to emission limits?
4. What are the costs of those work practices?

Health-Based Emission Limits:

1. Do you have the information that would support considering setting health-based emission limits under CAA section 112(d)(4) for HAP emissions from EGUs? For example, facility-wide HAP emissions, facility configurations, overall fence-line characteristics, population proximity to plant, potential adverse environmental effects that would otherwise be reduced or eliminated.

Other Potential Options/Flexibilities:

1. Are there other regulatory options or small entity flexibilities that EPA should consider?

<u>Cost Estimates</u>

Control Technology:

1. If you employ any of the control technologies listed on slide 26 of the outreach presentation as potentially being required to meet the Utility NESHAP, indicate the type of control, its size (e.g., the size EGU that the control is associated with, the exhaust gas flow rate being routed through the control), what the capital costs were, and what the annual operating costs are.
2. Do you agree with the control technology and monitoring cost estimates presented on slide 27 of the outreach presentation? ?   If not, provide your cost estimate(s) along with the source(s) of your estimate(s).
3. Do you employ other control or monitoring technologies that EPA should consider when estimating the impacts of the standards? If so, indicate the type of control or monitor, the size boiler it is associated with, what the capital costs were, and what the annual operating costs are.

Financial and Production Impacts:

1. In ideal circumstances, how long would your facility require to finance and install new emissions control and monitoring equipment?
2. How long would be required if there were other regulations requiring similar investments that had to be implemented consecutively?
3. How would new emissions requirements affect your production capacity?

Other Regulatory Requirements:

1. Are there other regulatory requirements that could conflict with new emissions standards?
2. Are there other regulatory requirements that could increase the cost of compliance with new emission standards?

Capital Availability:

1. How does your entity acquire money for capital investments? Is it primarily through equity? Or debt? Or a combination of both?
2. Are you an independent power producer?
3. Is your entity regulated by a State or local utility commission, or does it operate in competitive markets?
   If you had to install additional control equipment that required capital investment, would you adjust the rate charged to your customers?
4. What is the process for adjusting the rate?
5. What is the expected time for that change to occur?
6. What are the limits on how much you can raise rates?
7. What other constraints exist on your ability to raise capital or fund capital investment for regulatory compliance?

Appendix C

Written Comments Received from SERs

1. Alan Bonderman, Atlantic Municipal Utilities, Atlantic, IA

2. Erik Booth, Marquette Board of Light & Power. Marquette, MI

3. Donald Pauken, Muscatine Power & Water, Muscatine, IA

4. Joe Eutizi, San Miguel Electric Cooperative, Inc., Christine, TX

5. Ken Bapp, Texas Municipal Power Agency, Bryan, TX

6. Robert Tondu, Tes Filer City Station Power Plant - Tondu Corp., Houston, TX

7. James R. French, Wyandotte Municipal Services, Wyandotte, MI

Written Comments Received from non-SER Participants

8. Theresa Pugh, American Public Power Association (APPA)

9. Bill Wemhoff, National Rural Electric Cooperative Association (NRECA)

Comments - Utility MACT - Small Business Review Panel
ABonderman
to:
Madeline Barch
12/16/2010 03:19 PM
Cc:
RobertJ Wayland, David.rostker, Mary Johnson, Cortney_Higgins
Show Details

History: This message has been replied to and forwarded.

Ms. Barch:

Attached are comments from Atlantic Municipal Utilities, regarding the promulgation of regulations for control of hazardous air pollutants, referred to as the “Utility MACT” rules.

Allen Bonderman
General Manager
Atlantic Municipal Utilities
15 West Third Street
P.O. Box 517
Atlantic, IA 50022-0517
Tel. 712-243-1395
Fax 712-243-2028
email ABonderman@amu1.net

AMU

Atlantic Municipal Utilities

Madelyn Barch
Regulation Management Division
Office of Policy
U.S. EPA
barch.madeline@epa.gov

Re: Small Business Review Panel for the Electric Generating Unit Hazardous Air Pollutant Emission Standards

I appreciate the opportunity to comment regarding EPA's rulemaking to set maximum achievable control technology ("MACT") standards for hazardous air pollutant ("HAP") emissions from coal- and oil-fired electric utility steam generating units ("EGUs"). I was listed as a participant on the panel convened under the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA SER panel).

Atlantic Municipal Utilities (AMU) is a small municipally-owned utility system, serving some 4,300 electric and 3,300 water customers, in and near the community of Atlantic, Iowa. Atlantic is located in southwest Iowa, and has a population just over 7,000. AMU has a total annual peak of 26 megawatts, and retail sales just over 100 million kilowatthours.

Our power supply resources consist of a purchase power agreement with Western Area Power Administration (WAPA) for deliveries of about 7 megawatts summer, and 5 megawatts winter. We are a minority owner (2.5%) in a 690 MW coal-fired plant called Walter Scott Unit 3, located near Council Bluffs, Iowa, which provides us with 17 megawatts of capacity. All additional power needs are satisfied through a power purchase agreement with Missouri River Energy Services (MRES), a municipal joint action agency with headquarters in Sioux Falls, SD. Locally, we also own a 4 megawatt dual-fuelled Nordberg diesel generator, and a Solar dual-fuelled combustion turbine, which has low-NO_x controls.

Our Walter Scott 3 resource has, over the past several years, been upgraded with pollution control equipment and systems to decrease emissions, including low-NO_x burners, a neural network, scrubber and baghouse. Atlantic's share of these improvements was in the neighborhood of $7 million, which exceeded our original investment in the plant back in the late 1970's.

As to the MACT standards and SBREFA panel, due to conflicts in my schedule and other workload, I was unable to sit in on the meeting via conference call. I did, however, communicate with others on the panel, and have received some information and some comments regarding how the session went.

Atlantic Municipal Utilities - 15 West 3rd Street - Atlantic, IA 50022 - Tel. (712) 243-1395 - Fax (712) 243-2028

The EGU MACT rulemaking may be one of the most expensive rulemakings in the history of the electric utility industry. Its impact on small systems such as ours could be devastating, as owners of generation will be forced to install extensive new pollution control equipment, or to retire units. The SBREFA requires that EPA must carefully consider the impact its EGU MACT rule will have on small entities and must act to lessen the burden of that rule on those entities. From my perspective, the actions taken thus far in no way satisfy that requirement.

The first flaw in the process may be the identification of potential candidates for the Small Business Advocacy Review Panel. When telephoned about being selected to participate on this panel, I attempted to inform the EPA representative that I was not qualified to serve on a panel such as this, due to inadequate knowledge of environmental controls, their costs, and other background related to the rulemaking. When I received e-mail correspondence that showed the entire list of candidates, I noted that several parties from Iowa were shown as members. Those systems are communities with populations of less than 2,000, and the persons named have no more expertise in pollution control than I do. I noted participants from similarly sized entities in other states.

Then I discovered that the intention was to hold a single meeting, at which the Agency would explain the specific input they wanted, and the format in which their questions should be addressed in filings. A great majority of those questions are technical in nature, or require extensive knowledge about costs of control technologies. It appeared that few, if any, participants would have that level of knowledge.

Section 609 of SBREFA envisions that small business panels will review “any material the agency has prepared in connection with this chapter” ***including information required to be part of the initial regulatory flexibility analysis***. A regulatory flexibility analysis typically includes descriptions of significant alternatives to the proposed rule, differing compliance or reporting requirements or timetables that take into account the resources available to small entities, and the clarification, consolidation, or simplification of compliance and reporting requirements for small entities. The SER meeting related to these rules involved no preparation and distribution of these clarifications, consolidations or simplifications of the EPA regulatory options.

The EPA materials did not include possible rulemaking alternatives, nor any information about possible compliance or reporting options. Moreover, the material lacks any results of EPA’s analyses of the data from the extensive information collection request (“ICR”) that EPA identified as being critical to the promulgation of an EGU MACT rule**.** It seems obvious that EPA has failed to meet the statutory requirements,

As a non-expert, I am unable to address the specific items detailed in the panel’s materials, and which were discussed at the meeting. I can, however, and will, make some general comments which do not specifically address EPA’s questions.

As a small entity covered under SBREFA, our utility is supposed to receive consideration for any and all forms of relief from onerous regulations. AMU is a member of the American Public Power Association (APPA), which has also submitted comments. We see APPA as a voice for our system, and for some 1400 similar small entities, an undetermined number of whom will be directly or indirectly affected by the proposed regulations. APPA’s comments should be considered as comments from small entities, and APPA should not be precluded as a “viewer” and assigned to the sidelines as a spectator. Doing so effectively eliminates any meaningful input from the smallest of the affected entities, who have no expertise nor any other means to express their concerns. For a trade association to be disqualified on the basis that it itself is not a small business as defined in SBREFA is ridiculous, if not shameful. Who else can speak for us?

APPA’s comments, which we completely agree with, include positions such as:

1.) EPA is not complying with requirements of the Small Business Regulatory Enforcement Fairness Act of 1996, for several reasons described in APPA's filed comments.

2.) Inadequate time was allowed for input from small business.

3.) EPA failed to correctly identify the scope of the HPA's to be regulated, and did not provide any legal analysis for its shift from its 2004 analysis which stated that EPA has authority only to regulate mercury emissions from coal-fired EGU's.

I noted with interest press releases yesterday which stated that on December 7th, EPA announced that it had filed a motion in the federal District Court for the District of Columbia. The motion is seeking an extension in the current court-ordered schedule for issuing rules that would reduce harmful air emissions from large and small boilers and solid waste incinerators. The additional time is needed, the agency said, to re-propose the rules based on a full assessment of information received since the rules were proposed. Consideration should be given to doing the same with the Utility MACT regulations.

EPA should consider starting over with the SBREF process. The Agency should make a sincere attempt to identify participants who not only represent small business but who have sufficient expertise – including trade association representation of affected small entities. Sufficient time, and an adequate number of meeting opportunities, should be provided so that the participants can provide meaningful input. All requirements of the SPREF statute and regulations should be met, not just in spirit, but in fact.

Thank you for the opportunity to be heard.

Allen Bonderman
General Manager
Atlantic Municipal Utilities
15 West Third Street
Atlantic, IA 50022
ABonderman@amu1.net
712-243-1395

RE: EPA Utility MACT Small Entity Outreach Meeting
Erik K. Booth to: Madeline Barch 12/16/2010 11:46 AM
Cc: "Kirby D. Juntila", William Pyle

History: This message has been replied to and forwarded.

Madeline,

Thank you for the opportunity to submit comments (please see attachment) under the Small Business Advocacy Review Panel.

Erik Booth, P.E.
Manager of Utility Compliance
Marquette Board of Light & Power
2200 Wright Street
Marquette, MI 49855
Phone: (906) 228-0335
Fax: (906) 228-0359
email: ebooth@mblp.org

-----Original Message-----
From: Barch.Madeline@epamail.epa.gov [mailto:Barch.Madeline@epamail.epa.gov]
Sent: Thursday, December 16, 2010 9:41 AM
To: abonderman@amu1.net; bmu@bancroftiowa.com; scott.siddoway@rosi-boise.com; rex.butler@cipco.net; crmugas@crmu.net; mike.thatcher@cbpower.coop; dhaverland@dutil.com; lopsal@cityofgeneseo.com; dnally@hollandbpw.com; skulig@jamestownbpu.com; Erik K. Booth; montelp@zumatel.net; dpauken@mpw.org; jeutizi@smeci.net; lhopkins@sipower.org; joe@tonducorp.com; kbabb@texasmpa.org; jfrench@wyan.org
Subject: EPA Utility MACT Small Entity Outreach Meeting

Greetings,

This note is a reminder that written comments are due today regarding the Small Business Advocacy Review Panel for the EPA rulemaking " National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-fired Electric Utility Steam Generating Units."

Please send any comments to me (barch.madeline@epa.gov), and I will share them with all Panel members. If you plan to send sensitive information about your company, please clearly mark it as CBI (Confidential Business Information) so we can handle it appropriately.

Thank you for investing your time and effort to provide us with your comments and recommendations.

Madeline Barch
Regulatory Management Division, Office of Policy
USEPA #6440EE Ariel Rios North
P: 202.564.0234
F: 202.564.0965
E: barch.madeline@epa.gov

BOARD OF LIGHT AND POWER

CITY OF MARQUETTE
2200 WRIGHT STREET
MARQUETTE, MI 49855-1398

KIRBY D. JUNTILA
EXECUTIVE DIRECTOR

PHONE 906-228-0313
FAX 906-228-0329
PLANT FAX 906-228-0359

16 December 2010

Re: Small Business Advocacy Review Panel for the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-fired Electric Utility Steam Generating Units

The Marquette Board of Light & Power was selected on November 17, 2010 to serve as a Small Entity Representative (SER) to the Small Business Advocacy Review Panel for the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-fired Electric Utility Steam Generating Units. The Marquette Board of Light & Power owns and operates a 44 megawatt pulverized coal-fired boiler and two smaller stoker-fired boilers serving turbines less than 25 MW at the Shiras Steam Plant located in Marquette, Michigan. Our city consists of a population of approximately 21,000 people with an average household income of $35,000 according to the United States Census Bureau. Our service area is occupied by mostly residential ratepayers, commercial facilities, and institutions (the largest two being a hospital and University).

This rule (EGU MACT) along with the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Transport Rule), the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT) , Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities (Coal Ash Disposal Rule), and the Clean Water Act-Section 316(b) regulations pose a significant financial burden on non-profit small businesses such as the Marquette Board of Light & Power and small communities where there is little availability to spread out the cost of compliance.

We have prepared the attached list of comments and concerns that we hope will be addressed in the proposed rule. We appreciate the opportunity to comment and feel that reducing hazardous air pollutant emissions is necessary but must be done responsibly, and in a manner that considers the economic hardships that will be realized in conjunction with other pending regulatory requirements.

Sincerely,

Erik Booth
Manager of Utility Compliance

Impacts on Small Businesses from Multiple Regulations Proposed Simultaneously

Public power utilities, such as the Marquette Board of Light & Power, are not-for-profit electric systems owned and operated by the people they serve through a local government. The Environmental Protection Agency has proposed, within the last couple of years, a string of rules simultaneously that have tremendous economic impacts on small public power utilities. Each rule represents a cost burden of millions of dollars individually. Taken one at a time, compliance with these rules is possible on an economical basis. However, when the capital cost must be absorbed at once, small non-profit municipalities and their ratepayers will suffer economic hardships. Municipalities do not generate profits for shareholders. The municipal rate is set at a level to cover the cost of service provided. Increased costs cannot be offset by reducing profit margins because for a municipality there is none. Costs must be passed onto the end user.

The Marquette Board of Light & Power operates a strong competitive business that provides a "yardstick" for both consumers and government officials to measure the cost of providing wholesale electricity against the rates of local private power companies and local electric utility cooperatives. Our municipality is located in small community. Residential ratepayers could not absorb the cost of compliance with these rules if they are concurrently enacted. Small businesses (such as the local grocery stores, small retailers, locally owned gas stations, etc) would endure further hardships from a significant increase in electric rates in an already difficult economic climate. If the EPA continues on this path of enacting multiple large-scale regulatory requirements, then we strongly urge you to consider a separate category for small non-profit electric providers.

Timing of Compliance - Inability to Receive Competitive Pricing

If the EGU MACT follows the Clean Air Act section 112(i)(3)(A) timeframe (compliance within three years from the date the rule is finalized) and is implemented simultaneously with the Boiler MACT, then the Marquette Board of Light and Power will be competing with the other 1,200 coal-fired boilers that must comply with the EGU MACT along with the 578 units designed for coal firing that must comply with the Boiler MACT (source: pg. 32022 Federal Register/Vol. 75, No. 107/ Friday, June 4, 2010) to install additional air emission control technologies. Due to the limited number of manufacturers, the most competitive pricing and attention will go to the large-scale accounts. Small businesses such as the Marquette Board of Light & Power will not be able to obtain competitive pricing due to the industry demand on vendors for their products. This supply demand and limited time for installation must be taken into account so that small businesses will not be unfairly stuck with a rule that causes an unequal economic burden. Consideration should be given on the development of a phased (or staged) approach that require the largest emitters to install control technology,followed by a second phase for moderate emitters, and lastly followed by a third phase for the lowest emitters. This will accomplish the goal of reducing pollutants from the largest sources first and ending with the smallest of emitters.

Timing of Compliance - Inability to Schedule Outages

There will be significant constraint issues with the electric grid if the EPA decides to proceed with an EGU MACT, which requires all sources to comply within three years from the date the rule is finalized. This issue will be compounded further if the Boiler MACT is simultaneously enacted. There will be units that will not be able to schedule the long term outages necessary to install emission control technologies due to the high volume of EGU's that will be competing for an outage schedule. Utilities will be competing with each other in scheduling outages and the EGU MACT time constraints will not be flexible enough to take into account the timeframe needed so that each unit can go down and still satisfy the demands for power. In addition to electric supply constraints, the Marquette Board of Light & Power has previously had to adjust outage schedules due to the high demand and low availability of experienced Millwrights. This demand will increase significantly under the EGU MACT. Compliance within three years from the date the final rule is published is not achievable due to the competition to schedule outages while providing enough electricity to satisfy demand along with balancing the ability to hire experienced Millwrights for installation.

Additional Subcategory for Solid Fuel Boilers

The EPA needs to consider a co-firing subcategory for coal and biomass. A boiler burning a 50% coal/50% biomass blend may not meet the CO limit for coal (if the EPA decides to define a coal burning unit as one which burns more than 10% coal). Most states are moving aggressively to a Renewable Portfolio Standard. We hope that the EPA takes this into consideration and does not propose a rule that conflicts with the other national direction of moving away from coal combustion. Essentially, the Boiler MACT rule as proposed provides no incentive to burn biomass unless a boiler can operate on biomass alone. Burning biomass alone may not be feasible in existing coal-fired units. The EPA needs to consider adding a category that offers an incentive to offset the combustion of coal with biomass meeting limits somewhere between the units designed to burn coal and units designed to burn biomass. This needs to be taken into consideration so that the EPA does not implement a rule that would conflict with the Renewable Portfolio Standards being adopted by many proactive states in an effort to move away from electricity generated from the combustion of coal.

Particulate Matter (PM) Continuous Emission Monitoring System (CEMS)

Opacity has long been an indicator of good particulate emission controls. Opacity is a much more economical and proven method of monitoring over a PM CEMS, which carries an EPA estimated capital investment of $224,000 and annual cost of $63,000. PM CEMS offers no benefits to units that already have the Best Available Control Technology (BACT) installed and will already be below the proposed PM limit once published. Precedent is set from visible emissions limitations currently being used for compliance determination with particulate emission limits (see Michigan Department of Environmental Quality Operational Memo No. 14 attached).

Michigan Department of Environmental Quality: Operational Memo No. 14 – May 6, 1997 (page 5).

C. Processes With Particulate Emission Limits Less Than 0.10 Lbs/1000 Lbs

There is a reasonable air quality basis for including a visible emissions limitation less than 20% opacity for processes that have particulate emission limits less than 0.10 pounds per 1000 pounds of exhaust gas. Rule 331(1)(b) requires the Department to set particulate emission limits by application based on the "best technically feasible, practical equipment available" for processes not listed in table 31. Rule 331(1)(c) allows the Department to set particulate limits as a condition of a permit. Rule 331(1)(b) and (c) often result in a particulate emission limit less than 0.10 pounds per 1000 pounds. Additionally, sources often request limits less than 0.10 pounds per 1000 pounds in order to create a "synthetic minor" source or modification and avoid Rule 220 (back when there were particulate non-attainment areas in the State) or PSD review. Rule 301(1)(b) allows the Department to set a visible emission limit more stringent than 20% opacity as a condition of a permit. The Permit Section has tried to set the opacity limit such that it is consistent with the particulate limit. The rationale was to allow for a compliance determination without always requiring particulate emission testing. Typically, the opacity limit had been applied as a "linear function" of the particulate mass emission limit. The "linear function" assumes a 0 percent opacity for <0.01 pounds per 1000 pounds of gas and 20 percent opacity for 0.10 pounds per 1000 pounds of gas and that there is a linear relationship between these points (e.g., 0.05 #/1000# = 10 percent opacity). The use of the "linear function" is being replaced by the following rule-of-thumb:

Particulate Limit Range		**Visible Emission Limit**
(in #/1000# of exhaust gas)	(in grains/dscf)	(in Per Cent Opacity)
0.010 or less	0.0052	5
0.011 to 0.050	0.0053 to 0.026	10
0.051 to 0.075	0.027 to 0.039	15
0.076 or greater	0.040 or greater	20

Therefore, visible emission conditions less than 20% opacity should continue to be used for processes that have particulate emission limits less than 0.10 pounds per 1000 pounds of exhaust gas pursuant to Rule 331(b) and Rule 301(1)(c) in future permits to install and should be maintained where they appear in any permits being consolidated into an ROP. Especially where an applicant has requested and agreed to a specific visible emission limit less than 20% opacity in place of periodic particulate testing as a method of demonstrating compliance with a low particulate emission limit which establishes a "synthetic minor" source or modification.

The EPA estimated annual costs of $48,000-$63,000 for a PM CEMS is more than double what is currently spent on our annual continuous emission monitoring and continuous opacity monitoring systems. Installing additional and more burdensome monitoring puts unnecessary costs burdens to small businesses if compliance could be verified using more proven and economical options.

Energy Optimization

Energy optimization is a widely popular method of reducing air pollutant emissions and should be incorporated in the EGU MACT. However, there needs to be some clarity on the projects that can be completed without fear of litigation. EPA needs to include guidelines and a project specific list that owners of boilers can use for process changes and modifications to the facility that will not trigger New Source Review.

As the EPA is most certainly aware, the largest energy optimization steps that can be made are increasing the efficiency of the combustion units. The biggest gains can be made be replacing the metal alloys in feedwater heaters, economizers, condenser tubes, low and high temperature superheaters, install new regenerative air heaters, install more efficient steam turbine rotors, ect. The ambiguity of the projects that trigger NSR and the litigious atmosphere surrounding boiler upgrades has provided a disincentive for utility efficiency improvements. We urge the EPA to take the correct measures to not only set HAP emission limits, but also to take the substantial steps necessary to ensure that plants are operating efficiently by providing strong guidance on what repair projects can be made in the name of energy optimization without fear of NSR litigation. Options such as performing Energy Star Audits offer little value, even when the cumulative effect is taken into account, when compared to the cumulative energy efficiency savings that can be made by upgrading the heat transfer surfaces and process changes in the boilers.

Our concern is that EPA will focus on the nominal energy savings measures such as light bulb changes, automatic timer switches, or insulation and window replacements while neglecting the much larger more cumbersome, but significantly more beneficial, energy efficient projects such as boiler process upgrades that will offer much greater returns and environmental benefits.

EGU MACT SER Panel - MPW Comments
Don Pauken
to:
Bill Maxwell, Mary Johnson, Madeline Barch
12/16/2010 04:41 PM
Cc:
david.rostker, cortney_higgins
Show Details

Muscatine Power and Water (MPW) submits the following comments and responses to the "Questions for SERs" (See Attachment A).

MPW is a municipal utility that serves the City of Muscatine, Iowa (population 23,000) and certain limited adjacent areas with electric, water and telecommunications services. Muscatine is on the eastern side of Iowa along the Mississippi River about 200 miles west of Chicago. The utility has three coal fired boilers serving four turbine generators and providing process steam to its largest electrical customer. One boiler will be subject to the ICI Boiler MACT. The other two boilers will be subject to the EGU MACT.

MPW is a member of the Midwest Independent System Operator. As a participant in this organization, all electrical generation is bid into the MISO market and all native system load is purchased from the MISO market. MPW energy pricing must be competitive in order to be selected by MISO on a daily basis for supplying energy to the MISO region. Revenues from participating in the market contribute to keeping rates low for native system customers. Any limitations on market participation will impact revenues.

Specific issues of concern to MPW are:

- Installation of any air pollution control equipment will require downtime for the associated generating unit. During that period or periods MPW must continue purchasing power to supply native system load. However, revenues from supplying energy to the market will not be received. The result is that MPW not only incurs the cost of the pollution control equipment, but also experiences lost revenues. These circumstances can aggravate financial issues further when the utility is already dealing with the implications of the poor economy.

    - Timing of a new rule will affect the duration and timing of control equipment installation. If the effective date is a relatively short period (Three years for a MACT rule.), a shortage of labor and materials is likely to exist as a result of numerous generating units being affected by the rule. Economics dictates that vendors and contractors will serve large utilities first. Therefore small entities may not be able to meet a regulatory deadline and would need to cease operating their unit(s) until controls can be installed. This situation places another financial burden small entities.
    - Financing control equipment can add to the financial burden of the utility because it can be a costly and lengthy process. A first step in the municipal bond process is obtaining a rating from at least one of the rating agencies. MPW has ratings, but other small utilities may not. MPW's past experience for issuing municipal bonds is that the process takes about six months. This period must be factored into meeting a compliance deadline.
    - MPW envisions the need for subcategories to account for the variability in emissions from differences such as boiler types, coal rank, boiler size and unit type. EPA should develop a list of realistic subcategories that encompasses those factors that can affect emissions. Any MACT limits need to be tailored to subcategories in order to be realistic and equitable.
    - A MACT rule should address the variability found in HAP emissions from an individual source. Even within a subcategory, variability in HAP emissions occurs. For example, we observed one of three stack test runs for Hg that was noticeably higher than the other two. The boiler operation remained unchanged while this situation occurred.
    -
    - A complicating factor in Muscatine is that the city has a large industrial base for a relatively

small community. These industries contribute to local air quality issues. Specifically, more stringent NAAQS for $PM_{2.5}$, SO_2, NOx and probably 0_3 will result in violations that will need to be addressed by industries and MPW. These circumstances compound decisions associated with air pollutant emissions controls.

MPW appreciates being able to participate on the SER panel and hopes that EPA gives serious consideration to the concerns expressed by small entities. We also believe that an additional meeting or meetings of the SER Panel would be beneficial after EPA develops more definitive information that could be incorporated into the proposed rule.

Don Pauken
Manager Environmental Affairs
Muscatine Power and Water
3205 Cedar St.
Muscatine, IA 52761

563/262-3394

(See attached file: Questions Responses for SERs.doc)

ATTACHMENT A
MUSCATINE POWER AND WATER
RESPONSES TO EPA SER QUESTIONS

- **Affected Entities**
  - Is EPA's list of potentially affected small entities on slide A-4 of this presentation accurate? If not, do you have suggested additions or deletions? Could you briefly explain the reason for each addition or deletion? (Note: The applicable definitions of small entity are on slide 28 of this presentation.)
    Unqualified to answer this question.

- **Firm Characteristics**
  - How many units do you have in your facility or facilities?
    Three boilers serving four turbine/generators. Two of the three boilers will be subject to the EGU MACT. (One will be subject to the "Small Boiler" MACT.)

  - What is the capacity of your installed units?
    293.55 MW

  - What duty cycles do they run?
    The units do not operate in the historic base load or peaking modes. Muscatine Power and Water (MPW) is a member of the Midwest Independent System Operator (MISO). MISO dispatches (regulates output) the units in five minute intervals based on a combination of Day Ahead and Real Time market conditions. MISO operations are too complex to describe in this response, but MPW is willing to discuss MISO operations with EPA verbally.

- **Existing Standards**
  - What Federal/State/local standards are your EGUs currently subject to?
    Title V, NSR/PSD, Acid Rain Program, CAIR

  - What compliance requirements are associated with the other standards that apply to your EGU?

Parameter	Period	Unit 7	Unit 8/8A	Unit 9
Opacity	6-minute	40 %	40 %	20 %
Particulate Matter (PM)	1-hour	0.42 lbs./MBtu 121 lbs./hr.	0.30 lbs./MBtu 267 lbs./hr.	0.03 lbs./MBtu
SO_2	3-hour 24-hour 30- day rolling avg. Annual	6.0 lbs./MBtu 2,772 lbs./hr. [1)] N/A N/A	6.0 lbs./MBtu 2,772 lbs./hr. [1)] N/A Adequate allowances	N/A 0.56 lbs.MBtu 0.45 lbs./MBtu Adequate allowances

SO_2 % Removal	30-day rolling avg.	N/A	N/A	92 % minimum
NOx	30-day rolling avg. 30-day rolling avg. Annual 12-mo. rolling avg. Annual Seasonal	N/A N/A N/A N/A N/A N/A	N/A N/A N/A 0.86 lbs./MBtu Adequate Alwnc. Adequate Alwnc.	0.60 lb./MBtu [2)] 0.50 lb./MBtu [3)] 0.40 lbs./MBtu 0.235 lbs./MBtu Adequate Alwnc. Adequate Alwnc.
CO	1-hour 24-hour daily avg. 12-mo. rolling avg.	N/A N/A N/A	432.4 lb./hour 250 ppm 960 ton/yr.	329.2 lb./hour 100 ppm 720 ton/yr.

[1)] Unit 7 & 8 combined.
[2)] When combusting bituminous coal.
[3)] When combusting subbituminous coal.

- What emissions control technologies do you have installed at your facilities? Under what regulatory requirements are they installed? What did they cost to install? To operate?

Unit	Control Device	Reg. Requirement.	Capital Cost/Yr.	Operating Cost/Yr.
7	Cold side ESP	None	na/1976	$2,400/2009
8/8A	Cold side ESP OFA	None PSD	/1999 $2.0M/2008	$24,000/2009 na/2009
9	Cold side ESP OFA Wet scrubber	None PSD PSD/LAER	na/1982 $3.0M/2008 $33M/1982	$44,000/2009 na/2009 $308,000/2009

- What recordkeeping and reporting requirements are you subject to under other standards that apply to your EGU?
  Title V, Acid Rain Program, 40 CFR Parts 60 and 75, GHG Reporting, Iowa Hg Emissions Reporting.

- If your EGU is subject to emission limits, are there alternatives to monitoring emissions or stack testing that would be less costly to demonstrate compliance and, if so, how much less costly are the alternatives?
  Considering the parameters, probably not.

- Are there recordkeeping and reporting alternatives that would simplify the requirements?
  As long as requirements exist to demonstrate continuous compliance, no.

- Do you employ any monitors, for emissions or process parameters, to monitor the operation of your EGU?
  Yes, MPW uses gas and opacity stack monitors.

- What type of monitors and how many?
  Four SO_2, Two NOx, Four CO_2, Three flow, Two CO and Three opacity monitors.

- What were the capital costs and what are annual costs for each monitor?
  Total annual maintenance costs are about $30,000 for materials and $30,000 for labor.

Monitors Capital Cost ($)						
Type	***Unit 7***		***Unit 8***		***Unit 9***	
	Year	***Cost***	***Year***	***Cost***	***Year***	***Cost***
SO2	*2005*	*12,300*	*2005*	*12,300*	*2005*	*24,600*
NOx	*-*	*-*	*2005*	*12,300*	*2005*	*12,300*
CO2	*1995*	*na*	*1994*	*na*	*1994*	*na*
Flow	*1995*	*na*	*1994*	*na*	*1994*	*na*
CO	*-*	*-*	*2008*	*17,000*	*2008*	*17,000*
COM	*2000*	*34,000*	*1997*	*32,000*	*1997*	*32,000*

Note: Flow and opacity monitors are scheduled for replacement during 2011.

- Are these monitors in place for environmental regulatory reasons, insurance reasons, or other reasons?
  The monitors are used for demonstrating environmental regulatory compliance.

- Did you provide any of the monitoring data to the Agency during the recent Information Collection Request on Utility Boilers or another information collection request?
  Yes. MPW provided Hg and non Hg metallic HAPS stack test data for a 75 MWe nameplate cyclone fired unit.

- Do you employ measures to ensure that your EGU operates in an energy efficient manner?
  Yes.

- What are the energy efficient measures you employ?
  The units have distributive control systems. These systems use neural network software that is tuned to operate the boilers most efficiently. Parasitic power use is minimized. Electric motors are replaced with energy efficient ones. Generating unit building lighting is currently being evaluated and old fixtures and bulbs are being replaced with energy efficient ones. Compressed air systems operation is being optimized.

- Are these measures a result of regulatory requirements, initiated voluntarily, or employed for other reasons?
  The measures are initiated voluntarily as good business management practices.

- What are the estimated emissions reductions associated with the energy efficient measures?

Energy Efficiency Measure	**Cost ($)**	**kWh Savings/Yr.**	**CO_2 Reduction (Tons)/Yr**
Neural Network #8/8A	260,000	na	na
Neural Network #9	300,000	na	na
Plant Lighting	200,000	680,000	850
Plant Motors	na	34,262	42.5
#7&8 Compressed Air System Optimization	157,000	950,000	1,187.5

na = not available

- What are the costs of implementing the energy efficient measures?
  See table above.

- **Regulatory Alternatives**
  - What types of subcategories based on class, type, or size do you think EPA should consider and why?
    Boiler technology, coal rank and unit size affect emissions. One size does not fit all.

  - What surrogate standards do you think are appropriate?
    Opacity for PM (including PM-10 and PM-2.5)
    Coal sampling and analysis (CSA) combined with mass balance

  - What means of determining variability do you think EPA should consider?
    Uncertain.

  - Which subset(s) of HAP from EGUs, if any, do you think would meet the CAA section 112(h) requirements for establishing work practice standards in lieu of emission limits and what is the basis for your assertion?
    Uncertain.

  - What work practice standards are available to you?
    Efficient unit operations and preventive maintenance on pollution control equipment.

  - What work practice standards would you consider to be reasonable alternatives to emission limits?
    Preventive maintenance activities that could be specified in T V Operating permit.

- What are the costs of those work practices?
  Do not have data.

- Do you have the information that would support considering setting health-based emission limits under CAA section 112(d)(4) for HAP emissions from EGUs? For example, facility-wide HAP emissions, facility configurations, overall fence-line characteristics, population proximity to plant, potential adverse environmental effects that would otherwise be reduced or eliminated.
  No.

- Are there other regulatory options or small entity flexibilities that EPA should consider?
  Deminimis exemptions.

- **Cost Estimates**
  - If you employ any of the control technologies listed on slide 26 of this presentation as potentially being required to meet the Utility NESHAP, indicate the type of control, its size (e.g., the size EGU that the control is associated with, the exhaust gas flow rate being routed through the control), what the capital costs were, and what the annual operating costs are.
    One of two units (175.5 MW) has a wet scrubber for SO_2 removal. (See table above for costs.) Both units have NOx and CO limits. The units are operated to meet emission limits for both parameters. (This is a balancing act because lowering one increases the other.)

  - Do you agree with the control technology and monitoring cost estimates presented on slide 27 of this presentation? If not, provide your cost estimate(s) along with the source(s) of your estimate(s).
    No basis on which to evaluate costs.

  - Do you employ other control or monitoring technologies that EPA should consider when estimating the impacts of the standards? If so, indicate the type of control or monitor, the size boiler it is associated with, what the capital costs were, and what the annual operating costs are.
    No

  - In ideal circumstances, how long would your facility require to finance and install new emissions control and monitoring equipment?
    Availability of equipment and manpower, and environmental permitting would affect the timeline. These factors cannot be projected. The scope of the project would need to be defined in order to develop the cost. After the project cost is known, MPW estimates six months would be needed to obtain funding through municipal bonds.

How long would be required if there were other regulations requiring similar investments that had to be implemented consecutively?
Too many variables exist to provide an estimate.

- How would new emissions requirements affect your production capacity?
  Directly by requiring more station service power. Indirectly by increasing production costs in a competitive market. Directly by possibly "forcing" retirement of Unit 8/8A sooner than planned.

- Are there other regulatory requirements that could conflict with new emissions standards?
  Unknown

- Are there other regulatory requirements that could increase the cost of compliance with new emission standards?
  Yes, more stringent NAAQS. Muscatine will probably be declared non attainment for the new SO_2 standard. EPA has declared the state SIP for $PM_{2.5}$ to be deficient for the Muscatine area. Any new project affecting NO_2 would probably require reductions to show modeled compliance.

- How does your entity acquire money for capital investments? Is it primarily through equity? Or debt? Or a combination of both?
  A combination of both. Smaller projects are generally financed through equity and large projects are financed through debt.

- Are you an independent power producer?
  No. MPW is a municipal utility.

- Is your entity regulated by a State or local utility commission, or does it operate in competitive markets? If you had to install additional control equipment that required capital investment, would you adjust the rate charged to your customers?
  MPW is overseen by a locally appointed Board of Trustees. The utility is a member of the Midwest Independent System Operator and as such functions in a competitive market. All native system load is satisfied by purchases from the market and all generation is bid into the market. Capital investment would be recovered through retail rates.

- What is the process for adjusting the rate?
  Utility staff make rate adjustment recommendations to Board of Trustees. The Board takes action at a monthly meeting.

- What is the expected time for that change to occur?
  Rates are adjusted whenever the utility budget demonstrates additional revenue is needed to meet expenses. Typically rate adjustments take about six months.

- What are the limits on how much you can raise rates?
  The municipal utility Board of Trustees has rate making authority. The Board strives to keep rates reasonable. High rates would negatively impact local business and the local economy, which have already been hit by the recession.

- What other constraints exist on your ability to raise capital or fund capital investment for regulatory compliance?
  When regulatory compliance costs become so onerous that wholesale and customer rates become non-competitive raising capital will become an issue. Customers will resist increases, rating agencies and lenders will also balk and question the Utility's ability to repay the debt.

12/16/10

EPA Utility MACT Small Entity Outreach Meeting comments
Joe Eutizi
to:
Madeline Barch
12/16/2010 04:10 PM
Cc:
"Mike Kezar"
Show Details

History: This message has been replied to and forwarded.

Madiline,
Attached are comments submitted by San Miguel regarding EPA's review panel for the Electric Generating Unit Hazardous Air Emissions Rulemaking. Thanks for the opportunity to comment on this very important rule.

Please don't hesitate to let me know if you have questions or need additional information.

Joseph Eutizi
San Miguel Electric Cooperative
830-784-3411 ext. 226
jeutizi@smeci.net

Madelyn Barch
Regulation Management Division
Office of Policy
U.S. EPA
barch.madeline@epa.gov

Re: Small Business Review Panel for the EPA rulemaking " National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal and Oil Fired Utility Steam Generators"

Members of the Small Business Advocacy Review Panel:

San Miguel Electric Cooperative, Inc. (San Miguel) thanks the Small Business Advocacy Review Panel (Panel) for selecting San Miguel to participate as a Small Entity Representative in this process. San Miguel submits the following comments to the Panel on the EPA rulemaking, National Emission Standards for Hazardous Air Pollutants for Coal and Oil Fired Utility Steam Generators (Utility MACT). San Miguel's comments will cover the following topics:

- Possible areas of regulatory options that would minimize impacts on small entities
- Concerns on the Small Business Advocacy Review for this particular rule
- General Comments on Utility MACT
- Input on Questions from Presentation Packet

Introduction

The principal business of San Miguel is the production of electric energy in South Central Texas. San Miguel's electric production comes solely from one mine mouth coal-fired power plant in South Central Texas. This one coal-fired unit comprises 100% of San Miguel's generating capacity; average yearly output is 2.9 million megawatt hours. The coal-mine, which is adjacent to the generating facility, extracts a Yegua, Lower-Jackson lignite (a Group B Lignite). The lignite mine supplies fuel only for the San Miguel Generating Station and yearly produces on average 3.3 million tons of lignite. The generating unit fires only lignite provided by this mine. The San Miguel electric generating station was designed and built specifically for this locally available lignite fuel. This unit has been reliably providing power to its customers successful since 1982 with a yearly availability factor averaging approximately 84%.

San Miguel is a Generation and Transmission Cooperative (G&T) and power generated from the plant is ultimately distributed to 26 member cooperatives that serve approximately 570,000 end-user member-owners in 114 Texas counties. As a not-for-profit cooperative, San Miguel does not have shareholders and these member-owners bear all of the costs of owning and operating the San Miguel facilities – including the costs associated with regulations such as the Utility MACT rule.

San Miguel is a member of the National Rural Electric Cooperative Association (NRECA) and supports its comments to the Panel on the Utility MACT.

Regulatory Options

San Miguel specifically proposes the following recommendations for regulatory options that would minimize impacts on small entities:

- Coal Subcategorization
- Either/or Standard of Percent Reduction or Emission Limit
- Mine Mouth Plant or Transportation Infrastructure Limitations
- Long Term Rolling Average Due to Variability in Fuel
- Physical Site Constraints
- Financing Options
- Additional Time to Comply

I. Coal Subcategorization

San Miguel strongly suggests the use of subcategorization of coal including two lignite subcategories – one for Fort Union Lignite (North Dakota area) and one for Gulf Coast Lignite (Texas area). A definitive reason for lignite subcategories is the amount of mercury in the lignite. The Fort Union Lignite contains approximately one third the amount of mercury than the Gulf Coast Lignite, although this was not discovered during the 1999 ICR part II fuel sampling. Fort Union Lignite on average contains 6 to 10 pounds of mercury /TBtu where as the Gulf Coast Lignite on average contains 24 to 34 pounds per TBtu. The reason this was not discovered during part II of the 1999 ICR was the ASTM test method used - by the testing laboratory - method ASTM D 3684 was not accurate for coals containing high amounts of mercury.

San Miguel discovered the error in the amount of mercury in the fuel after we started performing monthly composite fuel analysis in the spring of 2003. For the first few months the analysis indicated mercury in the 6 to 9 pound/TBtu range, which was similar to the values submitted for the 1999 ICR. The laboratory had equipment problems in late 2003 and purchased different equipment to analyze mercury (the new equipment utilized a different method, Method D6416). In March 2004 San Miguel received a letter explaining the error in the coal analysis; specifically that the mercury content was understated. Using the new analysis method monthly composite samples increased mercury to the 21 to 53-pounds/TBtu range, and the average in 2004 was 31.9 pounds/ TBtu. San Miguel has continued to perform monthly composite fuel analysis; this information can be made available to the Panel if necessary.

This error in analysis was included with our comments submitted to the EPA on June 22, 2004 to Docket ID No. OAR-2002-0056 (the 2004 Utility Mercury Reductions Rule (UMRR) Proposal MACT alternative). This same laboratory, Advanced Analytical Laboratories in Tyler Texas, performed the fuel analysis for TXU Power. TXU also commented on the 1999 ICR data error in their letter to the EPA on June 29,2004 to Docket ID No. OAR-2002-0056.

The subcategorization based on coal rank under Section 112 MACT standards was recognized by the EPA in its 2004 Utility Mercury Reductions Rule (UMRR) proposed MACT alternative. The additional subcategorization for the two lignite types is a simple option that could help in minimizing the effect of this rule on this small entity, while still achieving significant mercury emission reductions.

II. Either/Or Standard of Percent Reduction or Emission Limit

The final rule should include an either/or standard of percent reduction or emission limits to allow the source to comply with the least expensive or burdensome option. This clearly would be helpful to small entities. The composition of the coal used at many facilities varies considerably over time due to several reasons. Coal produced from a single mine is diverse as a result of the dissimilarity in coal composition from different locations or layers in the mine. At San Miguel over the past six years we have seen month to month variations in our monthly composite coal sample that range between 17 and 48 pounds of Hg /TBtu and yearly averages varying between 24.5 and 31.9 pounds of Hg/TBtu.

San Miguel is a mine mouth facility and was designed to burn the lignite that is close to the plant; the infrastructure to unload coal trains is not present at the San Miguel facility, but there are many power plants that purchase coal from more than one mine because of market based cost and other considerations. In addition, many times coal from various sources is blended and, in some cases, even different coal types are combined in varying amounts for use in a single generating unit.

For all these reasons, the option of a percent reduction compliance method may be the most reasonable alternative to achieving the desired emission reductions while helping to minimize any unnecessary costs of compliance. In other instances, emission limits may be less burdensome. San Miguel believes that the source should be allowed to make the decision regarding which option to use; this will minimize the effect on the small entity, while achieving the desired reduction in mercury emissions.

III. Mine Mouth Plant or Transportation Infrastructure Limitations

A mine mouth electric generating station such as San Miguel which was built without transportation infrastructure to unload coal via railroad or is not on a navigable waterway is at a significant disadvantage to generating facilities that receive coal via railroad or river/ocean barge. If the only way to meet the new Utility MACT is to change fuels or to blend fuels this small entity will be looking at an additional estimated $70-100 million just to build the infrastructure to unload and burn the fuel. This estimate does not include the cost required to install the MACT control equipment or the higher cost for the new fuel.

Another factor is the loss of high paying jobs in our rural county if mining operation is curtailed (100% replacement fuel) or reduced (blending fuels). This would be a significant loss to the local residents, which make up a majority of the 200 employees at the mine and the loss of the tax basis to the county.

Also, as stated in the "Introduction", San Miguel was designed to burn a specific fuel that is located within a few miles of the electric generating facility. The steam generator was built especially to handle the specific local lignite fuel – low heat content (average 5250 Btu/lb), high ash (average 30%) and high moisture (average 30%) – it is unknown at this time if a total replacement fuel could be used without a major modification of the boiler.

San Miguel is very concerned with the possibility of having to change fuel if the mercury emissions standard is so low that current control technologies can not meet the required removal rate or emission limit. San Miguel has performed full scale tests as part of a Department of Energy grant with Energy and Environmental Research Center (EERC) in 2008 and 2009. The highest removal rate achieved was 81.7%, due to scrubber reemission. A scrubber additive was included in the 2009 test and it had little effect on the scrubber reemission. Reports can be provided to the Panel if needed.

In the proposed NESHAP (and in the alternative NSPS) for Electric Utility Steam Generators, the EPA decided "fuel switching is not an appropriate criterion for identifying the MACT Floor level of control for existing coal-fired units."(69 Fed. Reg. 4669, January 30, 2004) . Thus, consideration needs to be given whether each coal rank can meet the standard without forcing a unit to switch coal rank. Fuel switching is particularly problematic at mine mouth facilities that do not have transportation infrastructure to switch or blend fuels. San Miguel recommends the MACT standard not be finalized in a manner that would effectively require a fuel change (blending or completely), especially for mine mouth coal electric generating stations.

IV. Longer Term Rolling Averages Due to Variability in Fuel

As stated above in the "Either/Or Standard", the variability of mercury in fuel is significant for San Miguel on a month-to-month basis. San Miguel does not have knowledge of the other possible HAPs variability, and limit our comments to mercury. In order to provide for controls that can adjust for higher levels of mercury in the fuel, a longer-term rolling average – a 12-month minimum rolling average- is necessary. In addition to the variability in the fuel, the mercury analyzers are unreliable. San Miguel installed a mercury CEMS by Thermo Environmental three years ago. We have not seen more than 30 consecutive days of reliable information from our CEMS even though the OEM has had their best technician troubleshoot the equipment. The OEM has recently told us the analyzer installed will not work in our application. The CEMS was removed and we are awaiting a recommendation from OEM. Without a real time monitor, changes cannot be made to adjust for varying amounts of mercury in the fuel. A method such as sorbent traps would be necessary to give an after-the-fact analysis of mercury emissions. A longer rolling average may allow increases in the performance of the control device to reduce additional mercury in the future avoiding a deviation of a shorter rolling average.

San Miguel recommends an emissions standard that is a 12-month rolling average due to variability of mercury in fuel and the difficulty of measuring minute quantities of mercury.

V. Physical Site Constraints

This does not affect San Miguel but we understand this is a very real situation that electric generating facilities might need to address. Generating facilities such as those built in a city or units built along a waterfront may not be physically able to expand its footprint, and not able to install the control technology required by the Utility MACT. Small entities need to be given the flexibility as well, when hampered by physical site constraints. This may result in a limit higher than MACT for a significant time frame, something that can be met using a control device that would fit in the physical constraints of the site.

VI. Financing Options

San Miguel was financed using REA financing. San Miguel has only required one other long-term loan in its 25 years of operations and that was through RUS two years ago (mostly for environmental control projects). RUS loans are no longer available for coal-fired projects including environmental control upgrades. Small entities such as San Miguel will need to find additional sources of financing for major projects including environmental projects.

San Miguel recommends a change to RUS policy to allow loans for coal-fired projects to meet environmental regulations.

VII. Additional Time to Comply

Small entities are at disadvantage to compete with large electric generating providers in obtaining services. Large entities have the ability to sign a contract with a single contractor to provide services at multiple plants for both equipment and installation services. Many times these are for very large units and at sites with multiple units. These types of projects have the potential for good profit margins as compared to single or smaller size units. Although San Miguel has a medium size electric generating unit (400Mw capacity), it is a single unit site. Over the past few years San Miguel has seen lead times increase for both material and installation (manpower). San Miguel believes this is due to a combination of the following reasons: utilities installing scrubbers and SCRs to meet CAIR; the local effect on limited manpower due to infrastructure repairs, including refineries, from hurricane Katrina; and the global effect on materials due to the build-up of China and India electric systems.

This rule will likely increase or sustain the time required for the small entity to obtain the services required to meet the rule, since all coal-fired electric generating facilities will be vying for the same services including engineering design, control technology manufacturing facilities, qualified manpower for installation and financing.

San Miguel recommends that the small entities be given an additional three years to install the required emission controls.

Concerns on the Small Business Advocacy Review

San Miguel is very concerned with this review process for the following reasons:

1) EPA has not provided adequate time to review and comment on a rule of this importance. The process from notification of the SERs to the Panel meeting was two weeks (which included Thanksgiving holiday). After the meeting with the Panel the SERs only had two weeks to prepare written comments.
2) There was no pre-meeting held to go over information on the rule.
3) The EPA did not provide usable information or data in a sufficient form that would assist the SERs in assessing the potential impact of this rulemaking.
4) The meeting conference phone failed during the meeting, thus the SERs participating by phone missed out on discussions in the meeting room and the meeting was not extended to accommodate for the time lost to those on the conference call.

San Miguel understands that the EPA is under a Consent Decree timeline but with a regulation that is this important not only to the electric generating companies, but also to our national interest in a reliable electric system, the necessary time should be taken even if it requires the EPA to file a motion for an extension. The EPA recently requested an extension for the Boiler MACT deadline until April of 2012. A similar extension is warranted here to process the significant issues raised in public comments, which are similar to the issues for this rulemaking.

General Comments on Utility MACT

The NRECA has provided general comments to the Panel on Utility MACT. San Miguel is in agreement with those comments. We will not duplicate those comments since we are co-signing the NRECA comment letter.

Questions for SERs

Since time ran out during the Panel meeting on December 2, 2010 San Miguel will attempt to provide input on the questions contained in the appendix of the presentation.

Affected Entities

This topic is covered in the comment letter of NRECA and will not be duplicated here.

Firm Characteristics
San Miguel has a single generating station with a net capacity of 391 Mw. The unit is base loaded as is indicated by our annual capacity factor that is only one to two percent lower than our annual equivalent availability factor.

Existing Standards
What Federal/State/local standards are your EGUs currently subject to?
San Miguel is subject to all the standard federal regulations such as Title V permit, Title IV Acid Rain regulations, Current CAIR requirements, Texas NSR air permit and east Texas regulation on NOx (which limits NOx emissions to an average 0.165 lb/MMBtu).

What emissions control technologies do you have installed at your facilities? Under what regulatory requirements are they installed? What did they cost to install? To operate?
The San Miguel generating station was constructed with an electrostatic precipitator for control of particulate matter and a wet flue gas scrubber for control of SO_2. An overfire air system, low NOx burners and a neural network control system were added for NOx control to meet the Texas regulations. Capital costs for the ESP and WFGD are not provided since they were installed during the original construction of the unit. The OFA, LNB and NN total cost was $6.3 million. In addition, the WFGD was upgraded to improve SO_2 removal efficiency from 86% to 94% to meet CAIR regulations at a cost of $8.7 million. Operating costs to run the ESP range from $500,000 to $725,000 annually, while the WFGD annual operating cost range is between $7.5 million to $10 million.

What recordkeeping and reporting requirements are you subject to under other standards that apply to your EGU?
Public Utility Commission, EPA CAA, Texas Commission on Environmental Quality, and Texas Railroad Commission

Do you employ any monitors, for emissions or process parameters, to monitor the operation of your EGU? What type of monitors and how many? What were the capital costs and what are annual costs for each monitor? Are these monitors in place for environmental regulatory reasons, insurance reasons, or other reasons?
A single Continuous Emission Monitor is installed for each of the following: CO_2, CO, NOx, SO_2, Gas Flow, and Hg (currently removed from service). Each monitor was installed for environmental reasons. The capital cost of all monitors was between $30,000 and $50,000 except for flow and Hg, which were $120,000 and $390,000 respectfully.

Did you provide any of the monitoring data to the Agency during the recent Information Collection Request on Utility Boilers or another information collection request?
San Miguel did not submit data with the ICR but did indicate we would supply electronic records if requested. San Miguel's generating unit was not selected for stack emissions testing.

Regulatory Alternatives
What types of subcategories based on class, type, or size do you think EPA should consider and why?

1) Coal, including the subcategories for the two primary lignite's groups – Fort Union and Gulf Coast reasons are stated above.
2) Boiler type, wall fired and tangentially fired - tangentially boilers have lower NOx emission rates than wall fired units. Although NOx is not directly affected by this rule, CO may be used as a surrogate for other HAPs. NOx and CO are inversely related, thus the lower NOx emissions provide an advantage to tangentially fired units, as NOx is lowered (for CAIR or the Transport Rule) CO increases.

What surrogate standards do you think are appropriate?
San Miguel can only provide comments/concerns on alternative surrogates that EPA has suggested.

Using Particulate Matter (PM) as a surrogate is a concern since PM monitors would need to be installed and this technology is in its infancy and has not been proven to be reliable over varying load ranges. Another problem is with stacks that are wet, the PM monitor would need to be installed upsteam of the WFGD and this will not account for the PM removal that occurs in the wet scrubber. Both of these would lead to inaccurate data.

Using CO as a surrogate is a concern since NOx has an inverse relationship with CO. As an example as to how CO increases as NOx decreases, San Miguel installed LNB and an OFA system in the mid 2000s. When these were installed NOx dropped by more than 50%, while CO increased. Will this lead to units increasing NOx to decrease CO or visa versa?

What means of determining variability do you think EPA should consider?
As mentioned above a 12-month rolling average for emissions needs to be implemented due to the variability of fuel.

Are there other regulatory options or small entity flexibilities that EPA should consider?
As discussed above, the following regulatory options should be considered: Either/or Standard of Percent Reduction or Emission Limit; Mine Mouth Plant or Transportation Infrastructure Limitations; Physical Site Constraints; Financing Options; and Additional Time to Comply.

Cost Estimates

If you employ any of the control technologies listed on slide 26 of this presentation as potentially being required to meet the Utility NESHAP, indicate the type of control, its size (e.g., the size EGU that the control is associated with, the exhaust gas flow rate being routed through the control), what the capital costs were, and what the annual operating costs are?
As tested in February 2009, the WFGD exhaust is 2,738,000 ACFM. Costs are covered above in Existing Standards.

In ideal circumstances, how long would your facility require to finance and install new emissions control and monitoring equipment?
Ideal financing would come through RUS. Since this is currently unavailable for coal-fired generating units, San Miguel can only provide a best guess since we have never had to go to the market to obtain long term financing. San Miguel estimates a minimum of one year to obtain financing.

San Miguel also estimates the engineering, procurement and construction time to be two and one half to three years, for a total time of three and one half to four years. Under real world conditions additional time would be required due to the competition that will exist when all coal-fired units (approximately 1300) are vying for the same services at the same time. As stated above in "additional time to comply" the small entity is at a disadvantage when competing with a large entity.

How long would be required if there were other regulations requiring similar investments that had to be implemented consecutively?
San Miguel believes this is dependent on the amount of work and the willingness of lenders to provide financing for the new projects. San Miguel believes if all the rules were known, it would be easier and more cost effective to engineer for all rules at one time and install in a staggered manner so as to optimize and minimize the yearly down time of our only unit.

How would new emissions requirements affect your production capacity?
This will depend on costs of installing and operating the necessary emissions control devices as compared to other generating facilities. This will determine the economic dispatch order for our unit.

Are there other regulatory requirements that could conflict with new emissions standards? Are there other regulatory requirements that could increase the cost of compliance with new emission standards?
There are many potential regulations that could potentially conflict and/or increase cost of compliance. The list includes: GHG, CCR, NAAQS, TR, SCPP, and future effluent regulations.

How does your entity acquire money for capital investments? Is it primarily through equity? Or debt? Or a combination of both?
Currently, most capitol investment funds are acquired through debt.

Are you an independent power producer?
No, San Miguel is a Generation and Transmission Cooperative.

Is your entity regulated by a State or local utility commission, or does it operate in competitive markets?
Transmission rates are regulated by the PUC of Texas and are based on cost of service studies. Cost of services studies can be updated as needed.

If you had to install additional control equipment that required capital investment, would you adjust the rate charged to your customers? What is the process for adjusting the rate?
As stated in the "Introduction" San Miguel is a non-profit cooperative owned by the consumers they serve. Since San Miguel does not have stockholders that could share the costs of any increased cost, all costs - including any that may be required by this proposed rule - must be passed through to the distribution cooperatives we serve.
The Board of Directors, based on the operating budget prepared by management and approved by the Board, sets rates for generation annually. The Board can change rates during any given year if circumstances warrant. The Board of Directors consists of one representative (Director) from each cooperative that San Miguel serves. The owner-consumers of each distribution cooperative elect their Director.

San Miguel would like to once again thank the Panel for selecting us as a Small Entity representative on this very important industry regulation. We encourage the Panel to give further consideration in scheduling an additional Panel meeting once the EPA has progressed in its rulemaking preparation.

If you have any questions concerning these comments please contact me.

Sincerely,

Joseph G. Eutizi
Engineering Manager
San Miguel Electric Cooperative, Inc.
830-784-3411 ext. 226
jeutizi@smeci.net

Comments to SBA on EGU MACT rule TMPA
Ken Babb
to:
Madeline Barch, RobertJ Wayland, Mary Johnson, David.rostker@sba.gov, Cortney_Higgins@omb.eop.gov
12/16/2010 06:32 PM
Cc:
Jan Horbaczewski, Charles Chang, "tpugh@appanet.org", "Eleanor Babb - personal (twinkee987@hotmail.com)"
Show Details

Attached pleased TMPA's comments following our participation on the SBREFA SER panel for the utility MACT (oil and coal).

Serving the Cities of Bryan, Denton, Garland & Greenville

Small Business Review Panel for EPA's Rulemaking for Hazardous Air Pollutant Emissions from Coal- and Oil-Fired Electric Utility Steam Generating Units – Comments, December 16, 2010

What is TMPA

Texas Municipal Power Agency (TMPA) is a power production station located outside of Bryan/ College Station, Texas. Owned by the four member cities of Bryan, Denton, Garland and Greenville; TMPA provides efficient, clean electrical power at an affordable price to help communities prosper. TMPA operates as a non-profit municipality. We're also known as Gibbons Creek Steam Electric Station (GCSES). TMPA employs more than 150 people dedicated to safe, clean power generation. The four member cities vary in population from 27,000 to 220,000.

TMPA's single unit is a coal-fired tangential boiler rated at 470 net Megawatts.
TMPA's coal comes from the Powder River Basin (PRB) in Wyoming and is a low-sulfur fuel. TMPA uses an electrostatic precipitator to control particulate emissions and continues to reduce nitrogen oxide emissions by modifying the burners and by implementing computer control of boiler operations. TMPA plans to complete modifications to an existing flue gas desulfurization scrubber this spring to further reduce sulfur dioxide emissions. As a government agency, TMPA takes seriously its responsibility to protect the environment.

TMPA's Comments

TMPA appreciates the opportunity to participate on the SBREFA SER panel for utility MACT (oil and coal). TMPA intends this letter to provide documentation of our own perspective of this MACT's impact, particularly in light of the various other regulatory challenges, scheduled and proposed, all taking place at the same time. However we believe that our input would be even more valuable if we had even an outline of a proposal for what the MACT will look like. It is therefore our recommendation that the SBREFA SER panel be reconvened later this winter to allow such input.

As mentioned above a number of different regulatory changes are scheduled or expected in the next few years for electric utilities. To cover all media, TMPA has a total of three environmental positions. These three people are responsible not only for monitoring regulatory developments and planning to implement them, but also for all the day to day environmental responsibilities of our plant. TMPA therefore requests that EPA coordinate the various new regulations to minimize their impact on facilities with minimal planning staff.

Also the coordination should extend to the various regulatory programs that TMPA is subject to. TMPA has limited capital resources and has already invested heavily in existing pollution control equipment. Any new pollution control requirements should be designed to utilize existing equipment to the greatest extent possible.

New pollution control requirements should also recognize the emission reductions that have already been achieved. TMPA, like most small entities that have added control equipment, expects to have no HAPs emitted at major levels once the scrubber modification is complete. In addition to a MACT for major emission sources, EPA should propose area source limits based on generally available technology for non-major sources.

Sub-categorization of source types should not be limited to major versus minor. For example one important sub-category would be whether a plant operates as base load or peaking. However in Texas the new nodal market may require base load plants to operate at times more like a peaking plant and may even require peaking plants to maintain a steady load for a significant period of time. Also, setting up categories based on whether a plant burns PRB coal, lignite, fuel oil, or other fuel types would make sense. Most of the HAPs derive from various impurities present in the fuel. Therefore setting standards that recognize these natural variations in emissions would make sense. However plants may have to switch between fuels even more frequently in the future and so the ability to change sub-category with changes in fuel type will be important. Therefore, sub-categorizations should be structured so that plants may move from one category to another as conditions warrant.

Another particular concern for small entities is the lack of back-up generation. Should the addition of a new pollution control device require TMPA to end generation for many months our member cities would lose their primary source of electric power for that whole time.

The choice of monitoring requirements can also particularly affect small entities. TMPA's instrumentation and control staff must maintain not only our continuous emission monitors, but also all of the plant's process control and monitoring equipment. While a larger entity might have the staff to provide the extra care needed by a state of the art monitor such as a mercury monitor, TMPA and most other small entities do not.

Before TMPA can even begin the process of raising new capital funds it must seek the approval of all four member cities for the project. Many other small entities have similar time consuming decision making processes. The result of these slower processes would be that the larger entities would have a head start in accessing the limited markets for capital, material and engineering manpower for any project required to comply with the MACT. The larger entities would already have the advantage in these markets because they would be looking to hire for multiple projects. These two disadvantages taken together could cause small entities to be unable to access the markets in time to meet the MACT's three year compliance window.

Conclusion

While TMPA appreciates being invited to participate in the December 2, 2010 SBREFA SER panel meeting, we believe that the meeting lacked sufficient details about the MACT to allow panelists to provide a truly useful review. The major impact of the utility MACT to all electrical generation sources, but particularly to small entities, should mandate that EPA seek the most comprehensive information it can obtain. We therefore believe the panel should be reconvened when some details of EPA's MACT proposal become clearer.

TMPA strongly recommends that any EGU MACT proposal contain a variety of sub-categories to reflect the actual state of EGU operations and their varying environmental impacts, particularly sub-categories based on emission rates (major versus minor sources), fuel type, and generation rate. The proposal should also reflect the current state of the industry by including mechanisms to allow facilities to move from one category to another as operating and market conditions demand. Further, any proposal should reflect the particular concerns of small entities with respect to back-up generation, personnel requirements and lead time for major projects.

Thank you. For further contact at TMPA:

Ken Babb, Plant Environmental Specialist
Texas Municipal Power Agency
P.O. Box 7000
Bryan, Texas 77805
936-873-1516
kbabb@texasmpa.org

Ken Babb

Comments for Coal and Oil-fired EUSG Units - Rulemaking Process
Caudell, John F.
to:
Madeline Barch
12/17/2010 02:18 PM
Cc:
Joe Tondu, Erik Booth, "dnally@hollandpbw.org", "jfrench@wyan.org"
Show Details

History: This message has been forwarded.

Please accept the attached document as a timely comment from Mr. R. J. Tondu concerning the rulemaking process for the Coal and Oil-fired Electric Utility Steam Generating Units. Mr. Tondu has not signed the attached document, but has reviewed and approved it for distribution. If you require an official signed copy, please let me know.

Thank you for the opportunity to participate in these important (rules) discussions........John Caudell

December 17, 2010

To: Madeline Barch, USEPA

From: John F. Caudell, Representing TES Filer City / Tondu Corporation

Re: Proposed Small Entity Utility MACT

Both Mr. Tondu and I appreciate the exchange of information and perspectives from all Small Entity and federal conference participants concerning development of the proposed Utility MACT standards. We believe your representatives received a clear message that any MACT standard that would require the installation of additional emissions control equipment for the Small Entity (EGU) participants would require an extended compliance schedule significantly greater than 3 years. The availability of skilled labor and access to emissions control systems will likely be scarce, in the event these Small Entities have to compete for the same resources as the larger utilities, assuming they will also be attempting to comply with a new MACT during this same time period.

Additionally, the USEPA has recently proposed to extend the deadline to publish a final version of Boiler MACT until April 2012, primarily because of the large number of comments opposed to (1) the quality of the test data used to set the proposed emission standards and (2) the "cherry picking" of the lowest emission rates on a pollutant by pollutant basis without regard for the combustion interrelationships between some of the regulated pollutants. Furthermore, it was pointed out by multiple participants during our call that there are several conflicting regulations pertaining to GHG, the proposed Clean Air Transport Rule, and others that must collectively be considered when attempting to set emission standards under MACT. In general, USEPA must develop a more organized, comprehensive effort to regulate multiple pollutants from combustion sources. The current hap-hazard approach used by USEPA to regulate pollutants from combustion sources is technically flawed and consistently disregards basic combustion chemistry.

We recommend that USEPA stand down on developing proposed Utility MACT regulations until the Boiler MACT rules become final and the existing (utility) emissions data base is re-evaluated by experienced combustion professionals, to avoid the technical deficiencies noted in the Boiler MACT comments received during Y2010. USEPA should immediately request an extension of their voluntary consent decree so they may:

- Adequately analyze those lessons learned in the Boiler MACT rule development process to avoid making similar mistakes.
- Take additional time to thoroughly analyze the emissions data collected during the EGR ICR, which will serve as the basis for defining MACT for EGUs.
- Continue to meet with representatives of the utility industry to discuss the logistical impediments to implement MACT on some 1350 coal and oil fired EGUs.
- Consider the range of possible emission control options that can be used to allow for implementation to take place in an orderly fashion that will protect the integrity of the Grid, the national economy and national security

To propose a Utility MACT standard without consideration of the issues would result in a highly flawed draft rule, subject to multiple revisions and likely delay final issuance of the rule well beyong the schedule that could be accomplished by taking a more logical and thorough approach.

Wyandotte Comments to SBA on EGU MACT Ruleamaking 12-16-20110
James French
to:
RobertJ Wayland, Mary Johnson, Madeline Barch, David.rostker, Cortney_Higgins
12/16/2010 05:16 PM
Cc:
"Melanie McCoy", "Theresa Pugh"
Show Details

Attached are WMS's comments on the Small Business Review Panel for EPA's Rulemaking for Hazardous Air Pollutant Emissions from Coal- and Oil-Fired Electric Utility Steam Generating Units. Thank you for allowing Wyandotte to participate in this process and have the opportunity to have our comments considered. Having a rule that protects both the environment and the ability of WMS to provide cost completive electricity is critical.

James R. French
Assistant to the General Manager
Wyandotte Municipal Services
3005 Biddle Ave.
Wyandotte, MI 48192
Phone: 734-324-7114
Cell: 734-775-2777
Email: jfrench@wyan.org

Municipal Service Commission
Gerald P. Cole
Frederick C. DeLisle
James S. Figurski
Leslie G. Lupo
Michael Sadowski

WYANDOTTE MUNICIPAL SERVICES

Electric, Steam, Water
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Melanie L. McCoy
General Manager and Secretary
3005 Biddle Avenue, P.O. Box 658
Wyandotte, MI. 48192-0658
Telephone: (734) 324-7100
Fax: (734) 324-7119

December 16, 2010

Mr. Bob Wayland
Combustion Strategies Group Leader
U.S. EPA
Wayland.robertj@epamail.epa.gov

Ms. Mary Johnson
U.S. EPA
Johnson.Mary@epamail.epa.gov

Ms. Barbara Barch
Regulatory Management Division,
Office of Policy (U.S. EPA)
Barch.Madeline@epamail.epa.gov

Mr. David Rostker
Advocacy Counsel
Office of Advocacy
U.S. Small Business Administration (SBA)
David.rostker@sba.gov

Ms. Courtney Higgins
OIRA Desk Office- Air Regulations
Office of Management and Budget (OMB)
The White House
Cortney_Higgins@omb.eop.gov

Small Business Review Panel for EPA's Rulemaking for Hazardous Air Pollutant Emissions from Coal- and Oil-Fired Electric Utility Steam Generating Units

Wyandotte Municipal Services

In December 1889, the Wyandotte Electric Light Company, a private, for-profit company, began providing streetlights and retail electric service for the community. In 1892, local residents voted to create a municipal electric utility, which initially provided street lighting. In 1896, the municipal electric utility began serving retail and became a Department of the City of Wyandotte. Today that Department is known as Wyandotte Municipal Services (WMS) and provides not only electric services, but water and telecommunication services; including cable television, internet, and voice of internet phone (VOIP) services

Wyandotte's municipal electric utility is one of 41 public power systems in Michigan, and one of nearly 2,000 public power systems in the United States. It serves 12,939 consumers, has $36 million in annual revenues, and sold 282 million kilowatt-hours in 2010. Peak electric demands range from 65,000 to 70,000 kilowatts (65 to 70 megawatts).

The municipal electric system has three sources of supply to provide reliable, affordable service: the 70-megawatt municipal power plant, a 28-megawatt interconnection with Detroit Edison's 40,000-volt transmission system, and a 98-megawatt interconnection with Detroit Edison's 120,000-volt transmission system.

The municipal power plant consists of three boilers and four generators. Fuels include coal, natural gas and tire-derived fuel (TDF). TDF has a higher Btu or heating value than coal, is half the price of coal and produces similar emissions. About 26,000 tons of TDF (the equivalent of 3.5 million scrap tires) were consumed at the Wyandotte municipal power plant in 2006. In addition to supplying over 90% of all the electricity need of the residences and businesses in Wyandotte, the municipal power plant also supplies 100% of all the steam needs of BASF and Henry Ford Wyandotte Hospital.

The Wyandotte municipal electric distribution system consists of 12.5 miles of 69,000-volt transmission lines and 75.3 miles of 13,200-volt and 4,800-volt distribution lines. The municipal electric utility also installs, maintains and provides electricity for streetlights throughout the community without additional charge.

The significance of the EGU MACT standard

The EGU MACT rulemaking has the potential to be one of the most expensive rulemakings the utility industry has ever faced. Its impact on WMS could be enormous forcing us either to install extensive new pollution control equipment or even to close certain units. As set out in the statute, EPA must carefully consider the impact its EGU MACT rule will have on small entities and must act to lessen the burden of that rule on those entities.

The Small Business Regulatory Fairness Act (“SBREFA”) was enacted to provide small entities a meaningful voice in major federal rulemakings. Among the Act’s goals are to encourage the “effective participation” of small business in the federal regulatory process[1] and to create a more cooperative regulatory environment among agencies and small businesses that is less punitive and more solution oriented.[2] Section 609 of SBREFA envisions that small business panels will review “any material the agency has prepared in connection with this chapter” including information required to be part of the initial regulatory flexibility analysis.[3] <u>A regulatory flexibility analysis typically includes descriptions of significant alternatives to the proposed rule, differing compliance or reporting requirements or timetables that take into account the resources available to small entities, and the clarification, consolidation, or simplification of compliance and reporting requirements for small entities.</u>[4] **This SER meeting involved no preparation and distribution of these clarifications, consolidations or simplifications of the EPA regulatory options.**

The highly abbreviated nature of this particular small business review panel that has been established for the EGU MACT rule prevents small WMS members from having the meaningful

[1] 5 U.S.C. § 203(3).
[2] 5 U.S.C. § 203(6).
[3] 5 U.S.C. § 609(b)(4); *see also* 5 U.S.C. § 603(b)(3), (4) and (5) and 603(c).
[4] *See* 5 U.S.C. § 603(c).

advisory role contemplated by SBREFA.[5] Only one panel meeting was provided and after that meeting, panel members were given a mere 14 days to prepare written comments.[6] The materials provided by EPA just prior to the only panel meeting are little more than what the Agency typically offers in a notice of proposed rulemaking. This is not consistent with the three prior SBREFA SER panel meetings where WMS was invited to participate. Those included the Clean Water Act Section 316 (b) cooling water intake structures/entrainment and impingement of aquatic organisms, the ICI Boiler MACT rulemaking in 2003 (for <25 MW utilities) and others held in the last ten years where the WMS has been invited to attend and participate. This SER panel meeting held on Dec. 2, 2010 was slightly more consistent with the very unorthodox small entity outreach on the GHG Tailoring rule in 2009. WMS accepted the non-SER panel approach on GHG because of the unusual circumstances surrounding how CO_2 would be regulated and the cascade of regulatory actions following the CO_2 reductions from the Section 202 of the Clean Air Act for tailpipe standards onto the regulated stationary sources of industry. **However the EGU MACT HAPs regulation and the timing of that regulation required no truncated or shortened process for the SER panel**. **WMS believes that this one meeting makes a mockery of the productive goals of SBREFA and the SER panel process that have been so successful in identification of regulatory options in other programs**.

On this EGU MACT rulemaking the EPA materials did not include possible rulemaking alternatives nor any information about possible compliance or reporting options. Moreover, the material lacks any results of EPA's analyses of the data from the extensive information collection request ("ICR") that EPA identified as being critical to the promulgation of an EGU MACT rule**. As a result of the poor and inadequate preparation by the U. S. EPA and failing to meet the statutory requirements, WMS can offer only general comments on EGU MACT rulemaking.**

WMS urges that additional small business panel meetings be held following a better staff review of the data and that small entities (including all of those on this panel) be given the opportunity to comment on real regulatory alternatives once EPA reaches that point in its rulemaking process. WMS would be pleased to participate in that process.

General Comments on the EGU MACT Rulemaking

Listed below is a list of bullet items that WMS believes needs further consideration by EPA and that should be presented to the SER panel for comments.

1. **EPA failed to correctly identify the scope of the HAPs to be regulated**

At several places in the presentation material, EPA indicates that it *must* set emission standards that address all HAPs emitted from EGUs.[7] This conclusion is legally incorrect.

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[5] The presentation materials suggest that EPA was required to foreshorten the small business review process because it is under a consent decree which sets a tight schedule for the EGU MACT rulemaking. *See* Slide 8. However, the SBREFA review process is an important part of any major federal rulemaking. EPA should have factored that process into any rulemaking schedule it agreed to and defended before a federal district court judge. As a practical matter, the consent decree allows EPA to unilaterally return to the judge to request additional time to complete the EGU MACT rulemaking. If EPA feels so constrained by the consent decree that it cannot provide an adequate SBREFA review process, then it should ask the judge for a schedule extension.

[6] While providing only 14 days for written comments by panel participants, EPA nevertheless propounds six slides of questions for those entities. Many of those questions were answered by all EGUs in response to Parts 1 and 2 of the EGU MACT ICR. Others would require far more than 14 days to provide meaningful responses. If EPA is serious about wanting input on the questions it posed to panel members, then a much longer comment period should be provided.

[7] *See* Slides 9 and 13.

Because § 112(n)(1)(A) requires a predicate health finding before EPA can regulate EGUs under § 112, EPA's December 2000 regulatory determination only gave it authority to set MACT limits for mercury emissions from EGUs.

EPA has offered no explanation or legal analysis for its abrupt shift in its interpretation of its legal authority to regulate HAP emissions from EGUs under § 112(d).[8] EPA's 2004 legal analysis remains the correct one -- EPA only has authority to regulate mercury emissions from coal-fired EGUs.[9]

2. **The SBREFA SER failed to correctly address Setting MACT floors**

In recent § 112(d) MACT rulemakings, EPA has set MACT limits using a pollutant-by-pollutant approach. Under this approach, EPA identifies the lowest emitting units to determine the MACT floor for a given HAP. EPA then directs its attention to the next HAP, ignoring those units it just determined were the "best performing" in setting the MACT floor for the first HAP, and establishes the next MACT floor based on a different set of units. EPA repeats this process until MACT floors have been set for all HAPs. The end result is a set of MACT floors that do not represent the emission controls achieved by an *actual*, best-performing unit. Instead, they reflect the performance of a hypothetical, ideal unit that does not exist in the real world.

Section 112(d)(3) of the CAA expressly requires that emissions limitation for new units should not be less stringent "than the emissions control that is achieved in practice by the *best controlled similar source*." For existing units, the emission standards "shall not be less stringent, and may be more stringent than -- the average emissions limitation achieved by the best performing 12 percent of *sources*." CAA § 112(d)(3)(A) (emphasis added). Section 112(a) defines major and area sources as any "stationary source located within a contiguous area and under common control." That section also defines the term "stationary source" as having the same meaning as that term has under CAA § 111(a). That subsection of the CAA defines a "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant." CAA § 111(a)(3).

These statutory provisions reveal a clear congressional intent that MACT floors must be based on the actual performance of an actual source or sources. These statutory provisions do not allow MACT floors to be set on the basis of a hypothetical, ideal units nor do they allow the "emissions control" achieved by the best sources to be determined using a pollutant-by-pollutant approach on a changing group of best performing units.

As a factual matter, EPA's pollutant-by-pollutant approach makes no sense when applied to EGUs. By myopically focusing of one HAP at a time, EPA misses the antagonistic effects of given HAP limit will have on other regulated emissions. For example, the production of Carbon Monoxide (CO) during the combustion process in an EGU boiler is inversely related to NO_x production. If EPA were to set a surrogate CO limit for organic emissions, plants could not meet that limit if they were also required to minimize its NO_x emissions.

3. **Although the SBREFA SER panel did discuss Subcategorization, the discussions of Subcategorization were inadequate and overly brief.**

For a source category as broad and diverse as coal- and oil-fired power plants, EPA must establish subcategories before setting MACT limits. Section 112(d)(1) allows EPA to distinguish among "classes, types and sizes of sources" in setting MACT limits. In the presentation material,

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[8] This is another example of why this small business panel process is so deficient. The Agency has drastically shifted its legal analysis of § 112 with huge resultant regulatory implications without any explanation. Small entities are left to try to divine EPA's logic.

[9] Of course, EPA's legal authority to regulate mercury emissions hinges on the factual adequacy of its December 2000 regulatory determination. In 2004, EPA admitted that its December 2000 finding was factually in error. As the rulemaking record now stands, that conclusion remains valid.

EPA explains that it will evaluate a number of possible subcategorization approaches including boiler design, coal rank, unit type, oil type, and duty cycle. All of these factors are reasonable bases for subcategorization. **EPA should add <u>the size</u> of an EGU to the list of subcategorization approaches it considers.** <u>Beyond this general observation, WMS cannot provide more specific comments because of the lack of any analyses of the ICR data</u>. However, WMS hopes to identify other subcategorization concepts during a more detailed and effective SBREFA panel and during the official comment period after the proposed rule has been published.

Closely related to the issue of subcategorization is the question of whether EPA should set separate § 112 limits for EGUs that are area sources. *WMS discusses below why EPA should set area source limits for EGUs.*

4. **<u>Variability of pollutants:</u>**

The emissions of hazardous air pollutants are highly variable from a given EGU, even the best performing ones. The D.C. Circuit in *National Lime Ass'n v. EPA* held that where a statute requires a standard to be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur." 627 F.2d 416, 431 n.46 (D.C. Cir. 1980). The court expanded on this holding in *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999), when it stated that "[i]t is reasonable to suppose that if an emission standard is as stringent as 'the emissions control that is achieved in practice' by a particular unit, then that particular unit will not violate the standard." In order to assure that an emission limit is set at a level the best performing source(s) will not violate, EPA must assess the variability in emissions of that unit. *See Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004) (EPA's standard was reasonable because EPA recognized the large variability in emissions and supported its standard with record data). In *Sierra Club v. EPA*, 255 F.3d 855, 864-65 (D.C. Cir. 2001), the court instructed EPA to consider the efficiency of control equipment but also non-technology factors that may influence the emissions of the best performing units.

EPA's ICR required EGUs to conduct stack sampling over a three-day period. That snapshot of a unit's HAP emissions is not indicative or representative of the unit's emissions over longer periods of time. EPA must account for emissions variability in order to determine the level of performance achieved by the best performing units. EPA's presentation materials note the need to assess variability and identify three sources of variability that can affect a unit's HAP emissions: (1) fuel variability (both in the coal from a single mine as well as variability at plants that burn coals from multiple sources), (2) performance variability and (3) load variability. The critical question is how EPA plans to modify the stack emissions reported during the ICR to account for all these sources of variability. **<u>The presentation material provided by the EPA does not provide a detailed answer to this question. It simply notes that EPA used an upper predictive level ("UPL") of 99% in other MACT rulemakings without explaining how it would apply a UPL to the specific facts of the EGU MACT rule. WMS cannot provide meaningful comments on EPA's variability adjustments without more detailed information from EPA</u>.** What remains essential is that EPA properly and fully account for variability in setting MACT limits when proposing any rule.

5. **<u>Treatment of non-detects</u>**

Many HAP measurements made during the EGU ICR were at or below method detection and method quantitation limits. In addition, detection limit information was inconsistently reported by ICR test contractors. How EPA uses these very low measurements will have significant impacts on the MACT floors EPA calculates as well as later compliance demonstrations. **EPA's presentation material fails to explain how EPA will address measurements at or below a methods detection limit and quantitation limit.**

A large percentage of the dioxin/furan and non-dioxin organics measurements from ICR testing were at or below the method detection limit. For those two HAP categories, EPA should establish work practice standards instead of setting MACT limits. Section 112(h) of the CAA allows EPA to set work practice standards where it is not feasible to prescribe or enforce an emission standard. It is not feasible to enforce an emission limit when the uncertainty about the accuracy of a compliance measurement is as great as the measurement being report. This is the case when actual emissions are near the method detection limit. A work practice standard is the best way to avoid compliance issues where actual emissions at or below the detection and quantitation limits of a method.

6. **The use of alternative health based limits under § 112(d)(4)**

Section 112(d)(4) is designed to prevent the promulgation of unduly stringent emission limits simply for the sake of regulation. Section 112(d)(4) allows EPA to set health-based limits for certain HAPs based on established health thresholds as an alternative to promulgating technology based limits under § 112(d)(3). Section 112(d)(4) applies to non-carcinogenic HAPs[10] for which EPA has established a health threshold such as a reference concentration ("RfC") or a reference dose ("RfD"). EPA defines a reference concentration in its IRIS database as "[a]n estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime."[11] Thus, human exposures to a HAP at levels below its RfC are considered "safe", particularly given the uncertainty factors that EPA uses in its derivation of a RfC.

Section § 112(d)(4)'s inclusion in the 1990 CAA Amendments indicates a congressional intent to retain the health endpoint of the original § 112 -- protection of public health with an ample margin of safety.[12] If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation. **WMS strongly urges that EPA should set health-base standards under § 112(d)(4) when facts support its use, such as for acid gas emissions from coal-fired EGUs.**

7. **Monitoring**

A number of SBREFA provisions recognize the significant impacts monitoring and recordkeeping requirements can have on small entities. Federal agencies are encouraged to find ways to lessen the impact of monitoring and recordkeeping requirements on those entities. Small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as mercury and PM CEMs. EPA should develop more limited monitoring requirements for small EGUs. Unfortunately, EPA's presentation materials do not discuss any monitoring alternatives so more detailed comments are not possible. This was a prime example of a failure by the EPA staff to identify monitoring alternatives that could have been offered during the SER panel.

EPA Should Establish Area Source Standards

Section 112 of the CAA allows EPA to set area source standards for those stationary sources that do not emit or have the potential to emit more than 10 tons/yr of any individual HAP and 25 tons/yr of all HAPs.[13] If EPA decides to set an area source standard, it must use

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[10] Almost without exception, EPA assumes a linear, no-threshold dose-effect relationship for carcinogens.
[11] The definition for a reference dose is essentially the same except it focuses exposure by pathways other than inhalation.
[12] The ample margin of safety concept also underlies the current residual risk provisions of CAA § 112(f).
[13] A "major source" is defined in CAA § 112(a)(1) as a stationary source that emits HAPs above the 10

"generally available control technologies or management practices by such sources to reduce emissions of hazardous air pollutants."[14] Congress included an area source option in § 112(d) as recognition that the risks posed by HAP emissions from area sources were far smaller than the ones posed by major sources and that less stringent rulemaking standards were appropriate. Many EGUs owned by small entities are area sources. Some of these units are small (*e.g.* less than 100 MWs) and thus have relatively low HAP emissions. Others employ combustion processes (*e.g.* fluidized bed technology) or have installed control equipment (*e.g.* scrubbers) that reduce HAP emissions to levels that qualify them as area sources**.** **One of the few positive moments of the SER SBREFA panel meeting on December 2, 2010 was the point where we discussed the option of using area source standards. WMS strongly encourages the EPA to use area source standards for controlling mercury from smaller coal fired power plants**.

EPA should exercise its discretion, as it has done in other § 112 rulemakings,[15] and set separate area source standards for coal- and oil-fired EGUs.[16] Area source rules would lessen the regulatory burdens of a § 112 EGU rule on many small entities.

Small Entities Face Significant Compliance Problems with Any EGU MACT Rule

CAA § 112(i)(3)(A) requires existing sources to comply with a MACT rule no later than three years after the effective date of the MACT rule. Other provisions of § 112(i) provide possible extensions of the compliance date: one year by the EPA Administrator (or a State if it has implementation authority),[17] and an additional two years by a Presidential exemption.[18] While the entire utility industry will face great challenges to comply with a MACT standard within three years, small municipal EGUs will face far greater problems. It is highly unlikely those units will be able to meet a three-year deadline and EPA should extend the compliance deadline for those units as part of any final MACT rule.

The challenges for WMS is that it is located in an area where from our roof we can see three large (greater than 500 MW) coal fired power plants Those plants, simply by their size, will absorb all the engineering, suppliers, installers, and other resources necessary to comply with the regulations. Recently, MWS investigated converting our hot side ESP to a fabric filter and hired Black & Veatch to conduct a preliminary analysis. That anaylsis concluded that it would take a minimum of 40 months to complete the project. That analysis did not take into account having to compete for resources with 500 – 3200MW power plants.

Municipal utilities that qualify as small entities typically own one or two EGUs. If stringent emission limits are imposed by an EGU MACT rule, utilities across the country will

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tons/yr and 25 ton/yr thresholds. An "area source" is defined in CAA § 112(a)(2) as any stationary source that is not a major source.

[14] CAA § 112(d)(5).

[15] For example, EPA recently proposed area sources standards for certain industrial boilers.

[16] On Slide 7 of EPA's presentation material, the Agency notes that "[t]he section 112 definition of EGUs does not distinguish between area and major sources." One could interpret this bullet as suggesting that EPA believes it lacks legal authority to set area sources limits for EGUs. The definition of an "electric utility steam generating unit" in CAA § 112(a)(8) does not limit EPA's legal authority to set area source limits for those facilities. The most obvious reason an EGU definition was included in § 112(a) was because one was needed to identify which units were subject to the unique provisions of CAA § 112(n)(1)(A). Furthermore, Congress had already included generic definitions of "major" and "area" sources in § 112(a) so there was no need to include those terms in the later definition of an "electric utility steam generating unit."

[17] CAA § 112(i)(3)(B)

[18] CAA § 112(i)(4). The Presidential exemption can be granted more than once.

scramble to secure the equipment, contractors and skilled craftsmen needed to install new control equipment. Large utilities have leverage to get their plants retrofitted first. Small municipal utilities will find themselves at the end of a long line, making it highly unlikely that new control equipment can be installed within three years.

Small municipal utilities face additional daunting problems in complying with a MACT rule. The financing of new control equipment will be largely borne by the community served by the municipal utility. WMS members that qualify as small entities serve smaller communities that do not have large sums of money on hand to pay for extensive plant additions. Most municipals will need to seek external funding before beginning any design or construction activities

Some municipal power plants are also located very close to the population they serve. Those plants face space constraints that will prevent them for installing additional control equipment.

For all these reasons, EPA should provide small entities additional time to comply with the EGU MACT rule.

Conclusion

While WMS appreciates being invited to attend the December 2, 2010 SBREFA SER panel meeting as an observer or viewer, we believe that this process was inadequate, hastily convened, lacking in any serious regulatory alternatives to be offered for discussion, and lacking in any sincere effort to identify ways to reduce the costs and burdens of the largest single regulation in the utility sector. WMS also believes that the EPA has given only cursory thought to the reliability impacts to all of the various EPA regulations hitting the utility sector from 2013-2020 that are best identified on the diagram on page 3. **WMS believes that the SER panelists should be re-convened (by phone or in person) after the EPA has more thoroughly evaluated the sampling data and outlined several technical options and regulatory alternatives. These regulatory alternatives should include subcategorization and GACT controls and area source controls amongst other options.** Any regulatory options to reduce the cost to the many electric utility small party entities under SBREFA will also benefit the hundreds of thousands of commercial customers that are also SBREFA qualified commercial and industrial customers of electricity provided by public power**.**

James R. French
Assistant to the General Manager
Wyandotte Municipal Services
3005 Biddle
Wyandotte, MI 48192

jfrench@wyan.org
Phone: 734-324-7114

Utility MACT Small Business Review Panel - Comments
Cornwell, Laura
to:
RobertJ Wayland, Mary Johnson, Madeline Barch, David.rostker@sba.gov, Cortney_Higgins@omb.eop.gov
12/16/2010 04:05 PM
Show Details

Attached are the American Public Power Association's (APPA) comments on the Small Business Review Panel for EPA's Rulemaking for Hazardous Air Pollutant Emissions from Coal- and Oil-Fired Electric Utility Steam Generating Units.

We have also attached the comments of two of our members, Atlantic Municipal Utilities and the Marquette Board of Light & Power, which were submitted earlier today.

Thank you,

Laura Cornwell
Engineering & Environmental Assistant

American Public Power Association
1875 Connecticut Ave. NW, Suite 1200, Washington, DC 20009-5715

P: 202.467.2942
F: 202.495.7459
LCornwell@publicpower.org

www.publicpower.org

Small Business Review Panel for EPA's Rulemaking for Hazardous Air Pollutant Emissions from Coal- and Oil-Fired Electric Utility Steam Generating Units

What is APPA

The American Public Power Association (APPA) is the national service organization representing the interests of the more than 2,000, not-for-profit municipal and other state and local community-owned electric utilities that collectively provide electricity to approximately 45 million Americans. These utilities, or "public power" systems, are among the most diverse of the electric utility sectors, representing utilities in small, medium and large communities in 49 states (all but Hawaii). Seventy percent of public power systems are located in cities with populations of 10,000 or less. APPA was created in 1940 as a non-profit, non-partisan organization. Its purpose is to advance the public policy interests of its members and their consumers, and to provide member services to ensure adequate, reliable electricity at a reasonable price with the proper protection of the environment.

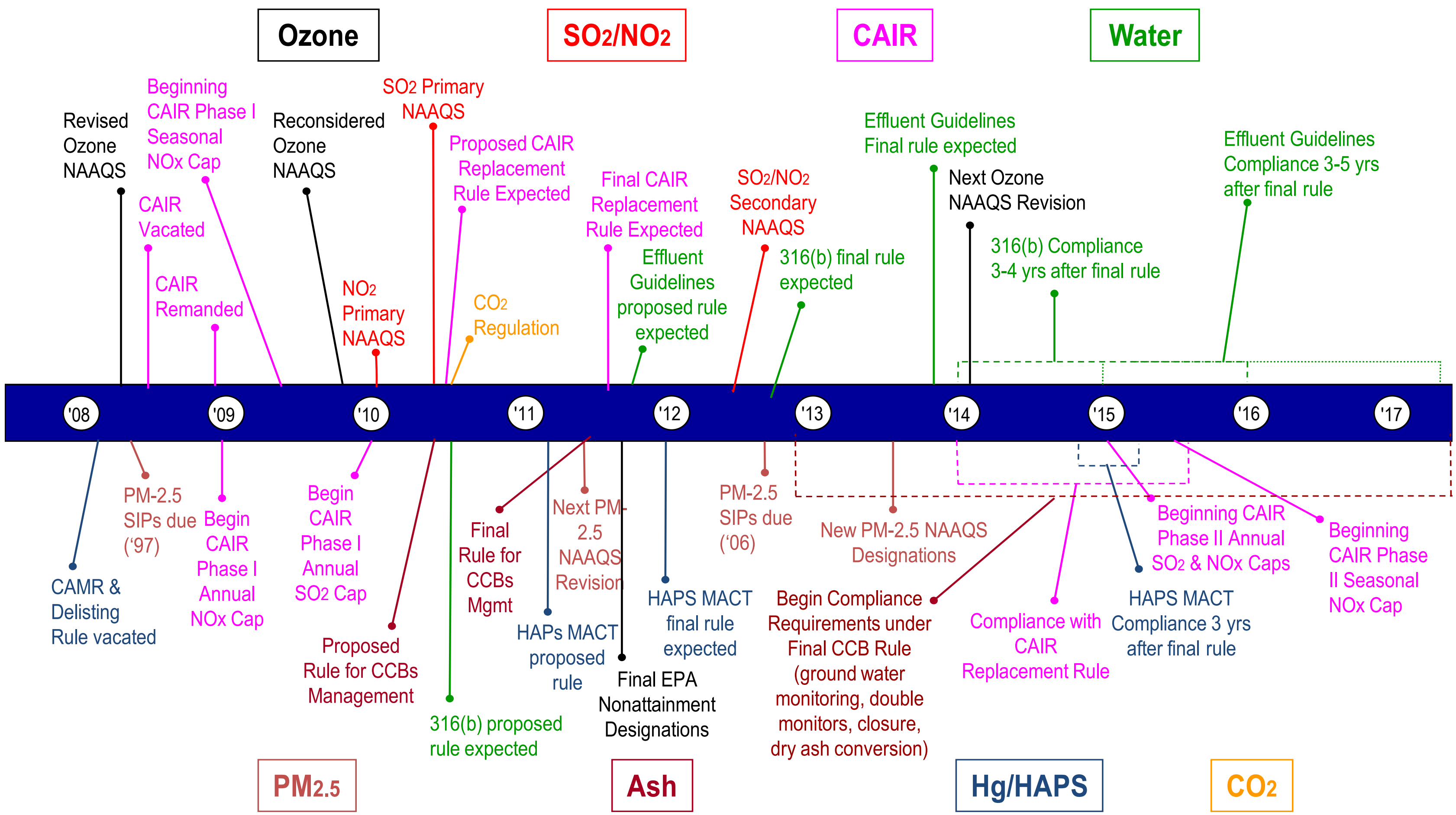
Overall, public power accounts for about 16 percent of all kilowatt-hour sales to retail electricity consumers. Approximately 46% of the megawatt hours of electricity produced by public power systems are generated using coal. Moreover, more than 90% of public power utility systems meet the definition and qualify as small businesses under the Small Business Act and the Small Business Regulatory Enforcement and Fairness Act of 1996 (SBREFA).

The significance of the EGU MACT standard

There are many environmental regulations hitting the utility sector in a window roughly bounded by 2014-2020 that require enormous investments, retirements, capital expenditures, and the raising of financial requirements through both cash and bonds at municipal public power utilities. These investments cannot be underestimated. Nor can the reliability issues be underestimated. It has been estimated by many that anywhere from 30-50% of the remaining coal-fired power plants might make the decision to close those coal fired plants due to the combination of MACT standards (likely requiring many control technologies) and scrubbers required by 2014 in many of the 31 states covered by Regional Transport (RT) rule's inadequate state allocations. These regulations will also be amidst a series of tighter ozone, PM 2.5, SO_2, NOx, and the new regulations for NSPS for Greenhouse gases (including CO_2, methane, and SF^6). Additionally, many power plants will face tighter controls for various water pollutants and possibly cooling towers to minimize aquatic organism harms from intake structures. These are best exemplified in the following diagram. These do not include other investments by power plants such as EPA regulations such as Toxic Substances Control Act (or TSCA) reporting, PCB phase out, transformer replacement and NERC's costly and time-consuming reliability standards.

Given the importance of these regulations, it is all the more important that the SBREFA SER panel for utility MACT (oil and coal) be thorough, thoughtful and valuable to the EPA, OMB and to the industry that SBREFA is designed to affect.

Possible Timeline for Environmental Regulatory Requirements for the Utility Industry



-- adapted from Wegman (EPA 2003) Updated 2.15.10

The American Public Power Association and its members appreciate the opportunity to participate in the small business review panel for EPA's rulemaking to set maximum achievable control technology (MACT) standards for hazardous air pollutant (HAP) emissions from coal- and oil-fired electric utility steam generating units (EGUs) through this panel convened under the Small Business Regulatory Enforcement Fairness Act of 1996 (or a SBREFA SER panel). APPA has been designated a "viewer" and many of the panel members are from public power utilities across the country.

The EGU MACT rulemaking has the potential to be one of the most expensive rulemakings the utility industry has ever faced. Its impact on APPA's smaller members could be enormous, forcing them either to install extensive new pollution control equipment or even to close certain units. As set out in the statute, EPA must carefully consider the impact its EGU MACT rule will have on small entities and must act to lessen the burden of that rule on those entities.

The Small Business Regulatory Fairness Act (SBREFA) was enacted by Congress to provide small entities a meaningful voice in major federal rulemakings. Among the Act's goals are to encourage the "effective participation" of small business in the federal regulatory process[1] and to create a more cooperative regulatory environment among agencies and small businesses that is less punitive and more solution oriented.[2] Section 609 of SBREFA envisions that small business panels will review "any material the agency has prepared in connection with this chapter" including information required to be part of the initial regulatory flexibility analysis.[3] <u>A regulatory flexibility analysis typically includes descriptions of significant alternatives to the proposed rule, differing compliance or reporting requirements or timetables that take into account the resources available to small entities, and the clarification, consolidation, or simplification of compliance and reporting requirements for small entities.</u>[4] **This SER meeting involved no preparation and distribution of these clarifications, consolidations or simplifications of the EPA regulatory options by the EPA.**

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[1] 5 U.S.C. § 203(3).

[2] 5 U.S.C. § 203(6).

[3] 5 U.S.C. § 609(b)(4); *see also* 5 U.S.C. § 603(b)(3), (4) and (5) and 603(c).

[4] *See* 5 U.S.C. § 603(c).

The highly abbreviated nature of this particular small business review panel that has been established for the EGU MACT rule prevents small APPA members from having the meaningful advisory role contemplated by SBREFA.[5] Only one panel meeting was provided and after that meeting, panel members were given a mere 14 days to prepare written comments.[6] The materials provided by EPA just prior to the only panel meeting are little more than what the Agency typically offers in a notice of proposed rulemaking. This is not consistent with the three prior SBREFA SER panel meetings on other proposed regulations where APPA was invited to participate. Those included the Clean Water Act Section 316 (b) cooling water intake structures/entrainment and impingement of aquatic organisms, the ICI Boiler MACT rulemaking in 2003 (for <25 MW utilities) and others held in the last ten years where the APPA has been invited to attend and participate. This SER panel meeting held on Dec. 2, 2010 was slightly more consistent with the very unorthodox small entity outreach on the GHG Tailoring rule in 2009. APPA accepted the non-SER panel approach on GHG because of the unusual circumstances surrounding how CO_2 would be regulated and the cascade of regulatory actions following the CO_2 reductions from the Section 202 of the Clean Air Act for tailpipe standards onto the regulated stationary sources of industry. **However the EGU MACT HAPs regulation and the timing of that regulation required no truncated or shortened process for the SER panel**. **APPA believes that this one meeting makes a mockery of the productive goals of SBREFA and the SER panel process that have been so successful in identification of regulatory options in other programs**.

On this EGU MACT rulemaking the EPA materials did not include possible rulemaking alternatives nor any information about possible compliance or reporting options. Moreover, the material lacked any results of EPA's analyses of the data from the extensive information

[5] The presentation materials suggest that EPA was required to foreshorten the small business review process because it is under a consent decree which sets a tight schedule for the EGU MACT rulemaking. *See* Slide 8. However, the SBREFA review process is an important part of any major federal rulemaking. EPA should have factored that process into any rulemaking schedule it agreed to and defended before a federal district court judge. As a practical matter, the consent decree allows EPA to unilaterally return to the judge to request additional time to complete the EGU MACT rulemaking. If EPA feels so constrained by the consent decree that it cannot provide an adequate SBREFA review process, then it should ask the judge for a schedule extension.

[6] While providing only 14 days for written comments by panel participants, EPA nevertheless propounds six slides of questions for those entities. Many of those questions were answered by all EGUs in response to Parts 1 and 2 of the EGU MACT ICR. Others would require far more than 14 days to provide meaningful responses. If EPA is serious about wanting input on the questions it posed to panel members, then a much longer comment period should be provided.

collection request (ICR) that EPA identified as being critical to the promulgation of an EGU MACT rule**. As a result of the poor and inadequate preparation by the U.S. EPA and failing to meet the statutory requirements, APPA can offer only general comments on EGU MACT rulemaking in these comments.**

APPA urges that additional small business SER panel meetings be held following a better staff review of the data and that small entities (including all of those on this panel) be given the opportunity to comment on real regulatory alternatives once EPA reaches that point in its rulemaking process. APPA would be pleased to participate in that process.

General Comments on the EGU MACT Rulemaking

1. **EPA failed to correctly identify the scope of the HAPs to be regulated**

At several places in the presentation material, EPA indicates that it *must* set emission standards that address all HAPs emitted from EGUs.[7] This conclusion is legally incorrect. EGUs are treated uniquely under § 112 of the Clean Air Act (CAA). Section 112(n)(1)(A) requires EPA to study the hazards to public health reasonably anticipated to occur as a result of emissions from EGUs "after the imposition of the other requirements of the CAA." After considering the results of that study, the EPA Administrator must then decide if further regulation is "appropriate and necessary." EPA completed the EPA Utility Study in February 1998. In December 2000, the EPA Administrator found that regulation of coal- and oil-fired EGUs was appropriate and necessary under § 112 and proceeded to list those units under § 112(c).[8] EPA's notice of regulatory finding focused solely on the risks to public health posed by mercury emissions from coal-fired power plants. Because § 112(n)(1)(A) requires a predicate health finding before EPA can regulate EGUs under § 112, EPA's December 2000 regulatory determination only gave it authority to set MACT limits for mercury emissions from EGUs.

When EPA first proposed MACT limits for EGUs in 2004, it went to great lengths to explain why it only had legal authority to set mercury MACT limits for coal-fired EGUs.[9]

[7] *See* Slides 9 and 13.

[8] 65 Fed. Reg. 79,825 (Dec. 20, 2000).

[9] *See* 69 Fed. Reg. 4,659-61 (Jan. 30, 2004).

Nothing has changed as a matter of law since EPA offered that analysis of its legal authority to regulate EGUs. The D.C. Circuit's later vacatur of EPA's removal of EGUs from the list of § 112(c) source categories in *State of New Jersey v. EPA*, 517 F.3d 574 (2008), avoided addressing legal arguments about the legality and scope of EPA's December 2000 regulatory determination. EPA has offered no explanation or legal analysis for its abrupt shift in its interpretation of its legal authority to regulate HAP emissions from EGUs under § 112(d).[10] EPA's 2004 legal analysis remains the correct one -- EPA only has authority to regulate mercury emissions from coal-fired EGUs.[11]

2. The SBREFA SER failed to correctly address Setting MACT floors

In recent § 112(d) MACT rulemakings, EPA has set MACT limits using a pollutant-by-pollutant approach. Under this approach, EPA identifies the lowest emitting units to determine the MACT floor for a given HAP. EPA then directs its attention to the next HAP, ignoring those units it just determined were the "best performing" in setting the MACT floor for the first HAP, and establishes the next MACT floor based on a different set of units. EPA repeats this process until MACT floors have been set for all HAPs. The end result is a set of MACT floors that do not represent the emission controls achieved by an *actual*, best-performing unit. Instead, they reflect the performance of a hypothetical, ideal unit that does not exist in the real world.

Section 112(d)(3) of the CAA expressly requires that emissions limitation for new units should not be less stringent "than the emissions control that is achieved in practice by the *best controlled similar source*." For existing units, the emission standards "shall not be less stringent, and may be more stringent, than the average emissions limitation achieved by the best performing 12 percent of *sources*." CAA § 112(d)(3)(A) (emphasis added). Section 112(a) defines major and area sources as any "stationary source located within a contiguous area and under common control." That section also defines the term "stationary source" as having the same meaning as that term has under CAA § 111(a). That subsection of the CAA defines a

[10] This is another example of why this small business panel process is so deficient. The Agency has drastically shifted its legal analysis of § 112 with huge resultant regulatory implications without any explanation. Small entities are left to try to divine EPA's logic.

[11] Of course, EPA's legal authority to regulate mercury emissions hinges on the factual adequacy of its December 2000 regulatory determination. In 2004, EPA admitted that its December 2000 finding was factually in error. As the rulemaking record now stands, that conclusion remains valid.

"stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant." CAA § 111(a)(3).

These statutory provisions reveal a clear congressional intent that MACT floors must be based on the actual performance of an actual source or sources. These statutory provisions do not allow MACT floors to be set on the basis of a hypothetical, ideal units nor do they allow the "emissions control" achieved by the best sources to be determined using a pollutant-by-pollutant approach on a changing group of best performing units.

As a factual matter, EPA's pollutant-by-pollutant approach makes no sense when applied to EGUs. By focusing on one HAP at a time, EPA misses the antagonistic effects of given HAP limit will have on other regulated emissions. For example, the production of Carbon Monoxide (CO) during the combustion process in an EGU boiler is inversely related to NO_x production. If EPA were to set a surrogate CO limit for organic emissions, plants could not meet that limit if they were also required to minimize its NO_x emissions.

3. **Although the SBREFA SER panel did discuss Subcategorization, the discussions of Subcategorization were inadequate and overly brief.**

For a source category as broad and diverse as coal- and oil-fired power plants, EPA must establish subcategories before setting MACT limits. Section 112(d)(1) allows EPA to distinguish among "classes, types and sizes of sources" in setting MACT limits. In the presentation material, EPA explains that it will evaluate a number of possible subcategorization approaches including boiler design, coal rank, unit type, oil type, and duty cycle. All of these factors are reasonable bases for subcategorization. **EPA should add the size of an EGU to the list of subcategorization approaches it considers when proposing the MACT rule.** Beyond this general observation, APPA cannot provide more specific comments because of the lack of any analyses of the ICR data. However, APPA hopes to identify additional subcategorization concepts during a more detailed and effective SBREFA panel and during the official comment period after the proposed rule has been published.

Closely related to the issue of subcategorization is the question of whether EPA should set separate § 112 limits for EGUs that are area sources. *APPA discusses below why EPA should set area source limits for EGUs.*

4. **Variability of pollutants:**

The emissions of hazardous air pollutants are highly variable from a given EGU, even the best performing ones. The D.C. Circuit in *National Lime Ass'n v. EPA* held that where a statute requires a standard to be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur." 627 F.2d 416, 431 n.46 (D.C. Cir. 1980). The court expanded on this holding in *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999), when it stated that "[i]t is reasonable to suppose that if an emission standard is as stringent as 'the emissions control that is achieved in practice' by a particular unit, then that particular unit will not violate the standard." In order to assure that an emission limit is set at a level the best performing source(s) will not violate, EPA must assess the variability in emissions of that unit. *See Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1242 (D.C. Cir. 2004) (EPA's standard was reasonable because EPA recognized the large variability in emissions and supported its standard with record data). In *Sierra Club v. EPA,* 255 F.3d 855, 864-65 (D.C. Cir. 2001), the court instructed EPA to consider the efficiency of control equipment but also non-technology factors that may influence the emissions of the best performing units.

EPA's ICR required EGUs to conduct stack sampling over a three-day period. That snapshot of a unit's HAP emissions is not indicative or representative of the unit's emissions over longer periods of time. EPA must account for emissions variability in order to determine the level of performance achieved by the best performing units. EPA's presentation materials note the need to assess variability and identify three sources of variability that can affect a unit's HAP emissions: (1) fuel variability (both in the coal from a single mine as well as variability at plants that burn coals from multiple sources); (2) performance variability; and (3) load variability. The critical question is how EPA plans to modify the stack emissions reported during the ICR to account for all these sources of variability. <u>The presentation material provided by the EPA does not provide a detailed answer to this question</u>. It simply notes that EPA used an upper predictive level ("UPL") of 99% in other MACT rulemakings without explaining how it would apply a UPL to the specific facts of the EGU MACT rule. **APPA cannot provide meaningful comments on EPA's variability adjustments without more detailed information from EPA**. What remains essential is that EPA properly and fully account for variability in setting MACT limits when proposing any rule.

5. **<u>Treatment of non-detects</u>**

Many HAP measurements made during the EGU ICR were at or below method detection and method quantitation limits. In addition, detection limit information was inconsistently reported by ICR test contractors. How EPA uses these very low measurements will have significant impacts on the MACT floors EPA calculates as well as later compliance demonstrations. **EPA's presentation material fails to explain how EPA will address measurements at or below a methods detection limit and quantitation limit.**

A large percentage of the dioxin/furan and non-dioxin organics measurements from ICR testing were at or below the method detection limit. For those two HAP categories, EPA should establish work practice standards instead of setting MACT limits. Section 112(h) of the CAA allows EPA to set work practice standards where it is not feasible to prescribe or enforce an emission standard. It is <u>not</u> feasible to enforce an emission limit when the uncertainty about the accuracy of a compliance measurement is as great as the measurement being report. This is the case when actual emissions are near the method detection limit. A work practice standard is the best way to avoid compliance issues where actual emissions at or below the detection and quantitation limits of a method.

6. **<u>The use of alternative health based limits under § 112(d)(4)</u>**

Section 112(d)(4) is designed to prevent the promulgation of unduly stringent emission limits simply for the sake of regulation. Section 112(d)(4) allows EPA to set health-based limits for certain HAPs based on established health thresholds as an alternative to promulgating technology based limits under § 112(d)(3). Section 112(d)(4) applies to non-carcinogenic HAPs[12] for which EPA has established a health threshold such as a reference concentration (RfC) or a reference dose (RfD). EPA defines a reference concentration in its IRIS database as "[a]n estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime."[13] Thus, human exposures to

[12] Almost without exception, EPA assumes a linear, no-threshold dose-effect relationship for carcinogens.

[13] The definition for a reference dose is essentially the same except it focuses exposure by pathways other than inhalation.

a HAP at levels below its RfC are considered "safe", particularly given the uncertainty factors that EPA uses in its derivation of a RfC.

Section § 112(d)(4)'s inclusion in the 1990 CAA Amendments indicates a congressional intent to retain the health endpoint of the original § 112 -- protection of public health with an ample margin of safety.[14] If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation. **APPA strongly urges that EPA should set health-base standards under § 112(d)(4) when facts support its use, such as for acid gas emissions from coal-fired EGUs.**

7. **Monitoring**

A number of SBREFA provisions recognize the significant impacts monitoring and recordkeeping requirements can have on small entities. Federal agencies are encouraged to find ways to lessen the impact of monitoring and recordkeeping requirements on those entities. Small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as mercury and Particulate Matter or PM CEMs. EPA should develop more limited monitoring requirements for small EGUs. Unfortunately, EPA's presentation materials do not discuss any monitoring alternatives so more detailed comments are not possible. <u>This was a prime example of a failure by the EPA staff to identify monitoring alternatives that could have been offered during the SER panel</u>.

EPA Should Establish Area Source Standards

Section 112 of the CAA allows EPA to set area source standards for those stationary sources that do not emit or have the potential to emit more than 10 tons/yr of any individual HAP and 25 tons/yr of all HAPs.[15] If EPA decides to set an area source standard, it must use "generally available control technologies or management practices by such sources to reduce

[14] The ample margin of safety concept also underlies the current residual risk provisions of CAA § 112(f).

[15] A "major source" is defined in CAA § 112(a)(1) as a stationary source that emits HAPs above the 10 tons/yr and 25 ton/yr thresholds. An "area source" is defined in CAA § 112(a)(2) as any stationary source that is not a major source.

emissions of hazardous air pollutants."[16] Congress included an area source option in § 112(d) as recognition that the risks posed by HAP emissions from area sources were far smaller than the ones posed by major sources and that less stringent rulemaking standards were appropriate. Many EGUs owned by small public power entities are area sources. Some of these units are small (*e.g.* less than 100 MWs) and thus have relatively low HAP emissions. Others employ combustion processes (*e.g.* fluidized bed technology) or have installed control equipment (*e.g.* scrubbers) that reduce HAP emissions to levels that qualify them as area sources. **One of the most positive moments of the SER SBREFA panel meeting on December 2, 2010 was the point where we discussed the option of using area source standards. APPA strongly encourages the EPA to use area source standards for controlling mercury from smaller coal fired power plants**.

EPA should exercise its discretion, as it has done in other § 112 rulemakings,[17] and set separate area source standards for coal- and oil-fired EGUs.[18] Area source rules would lessen the regulatory burdens of a § 112 EGU rule on many small entities.

Small Entities Face Significant Compliance Problems with Any EGU MACT Rule

CAA § 112(i)(3)(A) requires existing sources to comply with a MACT rule no later than three years after the effective date of the MACT rule. Other provisions of § 112(i) provide possible extensions of the compliance date: one year by the EPA Administrator (or a State if it has implementation authority),[19] and an additional two years by a Presidential exemption.[20] While the entire utility industry will face great challenges to comply with a MACT standard

[16] CAA § 112(d)(5).

[17] For example, EPA recently proposed area sources standards for certain industrial boilers.

[18] On Slide 7 of EPA's presentation material, the Agency notes that "[t]he section 112 definition of EGUs does not distinguish between area and major sources." One could interpret this bullet as suggesting that EPA believes it lacks legal authority to set area sources limits for EGUs. The definition of an "electric utility steam generating unit" in CAA § 112(a)(8) does not limit EPA's legal authority to set area source limits for those facilities. The most obvious reason an EGU definition was included in § 112(a) was because one was needed to identify which units were subject to the unique provisions of CAA § 112(n)(1)(A). Furthermore, Congress had already included generic definitions of "major" and "area" sources in § 112(a) so there was no need to include those terms in the later definition of an "electric utility steam generating unit."

[19] CAA § 112(i)(3)(B)

[20] CAA § 112(i)(4). The Presidential exemption can be granted more than once.

within three years, small municipal EGUs will face far greater problems. It is highly unlikely those units will be able to meet a three-year deadline and EPA should extend the compliance deadline for those units as part of any final MACT rule.

Municipal utilities that qualify as small entities typically often own only one or two EGUs. If stringent emission limits are imposed by an EGU MACT rule, utilities across the country will scramble to secure the equipment, contractors and skilled craftsmen needed to install new control equipment. Large utilities have leverage to get their plants retrofitted first. Small municipal utilities will find themselves at the end of a long line, making it highly unlikely that new control equipment can be installed within three years.

Small municipal utilities face additional daunting problems in complying with a MACT rule. The financing of new control equipment will be largely borne by the community served by the municipal utility. APPA members that qualify as small entities serve smaller communities that do not have large sums of money on hand to pay for extensive plant additions. Most municipals will need to seek external funding before beginning any design or construction activities.

Some municipal power plants are also located very close to the population they serve. Those plants face space constraints that will prevent them from installing additional control equipment.

For all these reasons, EPA should provide small entities additional time to comply with the EGU MACT rule.

Conclusion

While APPA appreciates being invited to attend the December 2, 2010 SBREFA SER panel meeting as an observer or viewer, we believe that this process was inadequate, hastily convened, lacking in any serious regulatory alternatives to be offered for discussion, and lacking in any sincere effort to identify ways to reduce the costs and burdens of the largest single regulation in the utility sector. APPA also believes that the EPA has given only cursory thought to the reliability impacts to all of the various EPA regulations hitting the utility sector from 2013-2020 that are best identified on the diagram on page 3. **APPA believes that the SER panelists should be re-convened (by phone or in person) after the EPA has more thoroughly evaluated the sampling data and outlined several technical options and regulatory**

alternatives. These regulatory alternatives should include subcategorization and GACT controls and area source controls amongst other options. Any regulatory options to reduce the cost to the many electric utility small party entities under SBREFA will also benefit the hundreds of thousands of commercial customers that are also SBREFA qualified commercial and industrial customers of electricity provided by public power**.**

Thank you. For further contact at APPA:

Theresa Pugh
Director
Environmental Services
APPA
202 467 2943
tpugh@publicpower.org or tpugh@appanet.org

EGU MACT SER Review Panel Comments
Wemhoff, Bill G.
to:
Madeline Barch
12/15/2010 03:12 PM
Cc:
Cortney_Higgins, david.rostker, RobertJ Wayland, Mary Johnson, "Johnson, Joseph", Mike Thatcher, rex.butler, lhopkins, jeutizi
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Madelyn –

Attached are comments submitted by the cooperative SERs regarding EPA's review panel for the Electric Generating Unit Hazardous Air Emissions Rulemaking.

By this message I am also copying others on the review panel that may have an interest in these comments.

Please don't hesitate to let me know if you have questions or need additional information.

Thanks for the opportunity to comment on this very important rule.

Bill Wemhoff

Sr. Principal, Environmental Policy

NRECA

ph (703) 907-5824

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Madelyn Barch
Regulation Management Division
Office of Policy
U.S. EPA
barch.madeline@epa.gov

Re: Small Business Review Panel for the Electric Generating Unit
Hazardous Air Pollutant Emission Standards
Comments
Rural Electric Cooperatives
December 15, 2010

The nation's rural electric cooperatives appreciate the opportunity to participate in the small business review panel regarding EPA's rulemaking to set national standards for electric generating unit ("EGU") hazardous air pollutant ("HAP") emissions based on the Clean Air Act's ("CAA") maximum achievable control technology ("MACT") provisions.

Below is a discussion of the many potential issues that cooperatives have expressed concern regarding the agency's EGU MACT rulemaking. Many of these issues were raised during our meeting on December 2 and are described in more detail here.

Overall Concerns

Electric cooperatives are very concerned that EPA has not provided adequate time for small entities to sufficiently review a rule of this magnitude and importance. With only a single meeting of the review panel that included the small entity representatives ("SER"), and with just a two-week timeframe in which SERs are required to submit written comments, their input will most certainly fall far short of what was intended by Congress when it passed the Small Business Regulatory Enforcement Fairness Act ("SBREFA").

Furthermore, EPA has not provided rule alternatives or sufficient data and information in a useable form that would allow small entities to assess the potential impact of this rulemaking. They, therefore, are limited in their ability to provide meaningful input on critical issues that could help shape the final rule in a way that would minimize the impact on small entities.

In addition, cooperatives are concerned that EPA's evaluation of the potential impacts of this rulemaking on small entities fails to account for a large number of potentially affected small electric cooperatives. While EPA has identified a few small cooperatives, we believe this is a gross underestimate of the true impact. We believe as many as 572 small cooperatives should be included in a thorough assessment of the regulatory and cost impacts of this major rule. Additional information supporting this position is included in attachment "A" hereto.

Finally, in its assessment, cooperatives believe EPA should consider the synergistic adverse impacts that this rule will have on small cooperatives in conjunction with the many other air-related rulemakings that the agency has ongoing. Cooperatives will experience disproportionately higher costs due to their greater dependence on coal-fired generation. Being non-profit, all costs will have to be passed on to their consumer-owners. Electric cooperative consumer-owners have household incomes about 14 percent less than the U.S. average and use more electricity, as a percent, when compared to residential consumers served by investor owned utilities and municipalities. Furthermore, because of the special challenges that cooperatives face, cooperative rates are already slightly higher than neighboring utilities. The consequence is that rulemakings resulting in increased costs of coal-based electric power, particularly in rural areas served by cooperatives, will have significant negative impacts on rural consumer owners, economic development and jobs. Included in appendix "B" is additional information describing some of the unique challenges facing cooperatives.

General Concerns Regarding the Potential Form of an EGU MACT Rule

EPA's final rule should be limited to mercury ("Hg") control only. The agency has not determined that emissions of other hazardous air pollutants in the quantities emitted, are detrimental to human health or the environment. In 2004, when EPA promulgated its HAPs control rule for electric generating units,[1] the agency offered (at pages 4659-61), a detailed legal analysis of why it believed it only had authority to set MACT standards for mercury under Section 112(d). Cooperatives concur with that analysis and believe that nothing has changed legally since that time. EPA, therefore, should limit the scope of this EGU MACT rulemaking to controlling Hg only.

Also, EPA has indicated that it intends to follow in this EGU MACT rulemaking, the same methodology it used in setting the HAP emission standards for industrial, commercial, and institutional boilers and process heaters[2] ("Ind. Boiler") rule. Cooperatives believe that EPA's methodology is flawed and fundamental data issues exist that compromise the validity of the proposed standards. Indeed, the agency has recently announced that it is reviewing its proposed Ind. Boiler rule and will delay finalization in order to ensure that the rule is practical to implement. NRECA filed extensive comments in response to the agency's proposal and identified many issues of concern. Those comments have been included as appendix "C", hereto. In addition, below is a listing of the major issues that were raised in those comments.

- The Section 112 MACT standard must reflect the emissions control achieved by actual units, not hypothetical composite ones. The proposed Ind. Boiler MACT limits were derived by determining independently a MACT floor for each HAP or HAP surrogate for each subcategory of sources. Under this approach, EPA identified the lowest emitting units to determine the MACT floor for a given HAP. EPA then directs its attention to the next HAP, ignoring those units it just determined were the "best performing" in setting the MACT floor for the first HAP, and establishes the next MACT floor based on a different set of units. EPA repeats this process until MACT floors have been set for all HAPs emitted by each subcategory of industrial boilers. The end result is a set of MACT floors that do not represent the emission levels achieved by an *actual*, best-performing unit.

[1] Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Proposed Rule, 69 Fed. Reg. 4652 (January 30, 2004)

[2] National Emission Standards for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Proposed Rule, 75 Fed. Reg. 32006 (June 4, 2010)

Instead, they reflect the performance of a hypothetical, ideal unit that does not exist in the real world. As NRECA explains in more detail in its comments,[3] Section 112(d)(3) of the CAA expressly requires that emissions limitation(s) for new units should not be less stringent "than the emissions control that is achieved in practice by the *best controlled similar source*." For existing units, the emission standards shall not be less stringent than the average emissions limitation achieved by the best performing 12 percent of *sources*. EPA's methodology for setting MACT floors is inconsistent with these requirements.

- A MACT rule must address in a reasoned manner HAP emissions that are at or below the method detection and quantification limits. EPA's effort to set emission limits for all HAPs will be greatly complicated by the fact that a number of HAPs are emitted at levels at or below the detection limit of the method that was used to collect and analyze HAP emissions during the MACT information collection request ("ICR"). Detection limit issues have significant impacts on MACT standard setting, as well as later during compliance demonstrations. CAA Section 112(h) provides that if it is not feasible to prescribe or enforce an emission standard for control of a HAP pollutant, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard. Electric cooperatives urge EPA to promulgate work practice standards as a replacement for emission limits to the fullest extent allowed. In any event, EPA needs to address these non-detect HAP emissions in a comprehensive fashion prior to setting MACT standards in its final rule.

- The rule must account for all variability in HAP emissions. In order for a standard to be achievable, it must be achievable under most adverse circumstances which can reasonably be expected to recur. In order to ensure that an emission limit is set at a level that the best performing source(s) will not violate, EPA must assess the variability in emissions of that unit.

[3] Comments by NRECA in response to Ind. Boiler rule, Docket ID No. EPA-HQ-OAR-2002-0058, dated August 23, 2010.

In EPA's presentation material for its SER outreach meeting, EPA indicated that it will evaluate a number of possible subcategorization approaches including boiler design, coal rank, unit type, and duty cycle. The broad use of subcategories is strongly encouraged. Section 112(d)(1) of the CAA allows the Administrator to distinguish among "classes, types, and sizes of sources" in establishing MACT standards. This subcategorization language mirrors earlier language found in CAA Section 111. In providing EPA discretion to create subcategories, Section 112(d)(1) does not restrict subcategorization to cases where the "class," "type" or "size" factors affect HAP emissions. The provision merely requires EPA to establish regulations for each category or subcategory on the schedules set out in Section 112. Indeed, EPA has not previously subcategorized under Section 111 based solely on emission effects. For example, under Section 111, EPA has subcategorized boilers on the basis of size (heat input) or the type of fuel burned (coal, oil or gas). These subcategorization decisions were based on feasibility and/or cost considerations, not on the level of emissions. Moreover, historical testing has shown that coal rank has a significant effect on Hg and hydrogen chloride ("HCl") emissions. In addition, we believe the lignite coal rank should be subcategorized by recognizing the differences in the characteristics of the Gulf Coast lignite and the North Dakota lignite. These coals have significantly different composition that will make it very difficult for them to comply with a single standard. Similarly, in the Illinois basin, the quality of the coal varies considerably even within the basin.

- MACT determinations must be based on the top 12 percent of all units in the category or subcategory and not 12 percent of those units that were tested in that category or subcategory. The CAA requires EPA to set MACT limits for existing sources based on "the average emissions limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emission information)." For source categories with less than 30 sources, existing source MACT floors are to be set based on "the average emission limitation achieved by the best performing five sources (for which the Administrator has or could reasonably obtain emissions information)." Cooperatives believe these two provisions indicate that Congress intended MACT standards to be set on a no less than five "best performing" units. It is fair to assume that Congress never contemplated the situation were the amount of available data from a large source category or subcategory would require EPA to set MACT limits based on the performance of only one or two sources as the agency did in the Ind. Boiler rule.

- HAP emissions during startup/shutdown events (which could produce emissions different from emissions during normal operation) should be addressed through long-term rolling averages. The EGU ICR did not require any testing during start-up, shutdown and malfunction events. Without emissions data during these periods, EPA has absolutely no factual basis for concluding that the best performing units can achieve the proposed MACT limits during these events. For example, operations during boiler start-ups are different than normal plant operations. Certain plant components must be started in a specific sequence in order to ensure that steady state operations can be achieved. During start-up, not all pieces of control equipment will be operating at peak efficiency. Cooperatives believe work practice standards are far more appropriate during these periods. Similarly, for the same reasons, work practice standards are also more appropriate for shutdown and malfunction events.

- Monitoring, reporting and record keeping requirements should be minimized and simplified to the maximum extent possible. At this preliminary stage in the rulemaking process, however, and having essentially no detailed information regarding specific emission standards or knowing what the agency is considering for monitoring and recording methodologies and criteria, it is not possible for cooperatives to provide specific recommendations or suggestions as to how to minimize the impact on small entities.

- The final rule should include an either/or standard of percent reduction or emission limits to allow the source to comply with the least expensive or burdensome option. This clearly would be helpful to small entities and would not detract from reducing emissions. The composition of the coal used at many facilities varies considerably over time due to several reasons. Coal produced from a single mine is diverse as a result of the dissimilarity in coal composition from different locations or layers in the mine. Also, many power plants purchase coal from more than one mine because of market-based cost and other considerations. In addition, many times coal from various sources is blended, and in some cases, even different coal types are combined in varying amounts for use in a single generating unit. For all these reasons, the option of a percent reduction compliance method may be the most reasonable alternative to achieving the desired emission reductions while helping to minimize any unnecessary costs of compliance. In other instances, emission limits may be less burdensome. Cooperatives believe that the source should be allowed to make the decision regarding which option to use.

- Health-based emission limits under Section 112(d)(4) should be used to the maximum extent possible. Section 112(d)(4) is designed to prevent the promulgation of unduly stringent emission limits simply for the sake of regulation. Section 112(d)(4) allows EPA to set health-based limits for certain HAPs based on established health thresholds, rather than having to follow the technology forcing provisions of Section 112(d)(3). As a practical matter, Section 112(d)(4) applies to non-carcinogenic HAPs for which EPA has established a health threshold such as a reference concentration ("RfC") or a reference dose ("RfD"). EPA defines a reference concentration in its IRIS database as "[a]n estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime."[4] Thus, human exposures to a HAP at levels below its RfC are considered "safe," particularly given the uncertainty factors that EPA includes as part of its derivation of an RfC.

[4] The definition for a reference dose is essentially the same except it focuses exposure by pathways other than inhalation.

Section 112(d)(4)'s inclusion in the 1990 CAA Amendments indicates a Congressional intent to retain the health endpoint of the original Section 112 -- protection of public health with an ample margin of safety. If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation. Cooperatives encourage EPA to set health-based standards under Section 112(d)(4) when facts support its use.

- Section 112 of the CAA defines a "major source" as a stationary source that emits HAPs in amounts greater than 10 tons/yr of any individual HAP or 25 tons/yr of all HAPs. Section 112 also allows EPA to set less onerous area source standards for any stationary source that is not a major source. Area source standards are based on "generally available control technologies or management practices by such sources to reduce emissions of hazardous air pollutants."[5] Congress recognized that the risks posed by HAP emissions from area sources are far smaller than the ones posed by major sources and that less stringent emission standards were, therefore, appropriate. Many EGUs owned by cooperatives qualify as area sources because they have control equipment installed or for other reasons.

  EPA should exercise its discretion, as it has done in the in the Ind. Boiler rulemaking, for example, and set separate source standards for those EGUs that qualify as area sources, This would have the effect of lessening the regulatory burdens on small entities.

Cooperatives are also concerned that specific units subject to the new EGU MACT emission limitation requirements may have site unit-specific special considerations that must be addressed in a final rule. For example:

- Specific units may not have the physical space to add the required control equipment. Consideration must be given to alternative compliance for these units

[5] CAA Section 112(d)(5).

that will avert the otherwise necessity to be shutdown and taken offline prematurely.

- The final rule must include consideration of the fact that for some small entity sources, fuel switching is not a reasonable or practical alternative to meeting new emission limits. For example, units with mine-mouth operation and having a lack of transportation infrastructure may have no option but to shut down if faced with overly stringent standards for the coal being used. We believe the CAA was designed to require sources to reduce emissions not to force groups of plants to cease operation. Furthermore, fuel switching implicitly favors certain fuel types and sources over others. A regulatory policy that favors one fuel type over another can have severe impacts on electricity reliability and energy security. Cooperatives believe that the potential negative impacts on small entities must be considered if the agency sets EGU MACT limits at levels that may require fuel switching. Furthermore, cooperatives believe that it is absolutely imperative that the EGU MACT rule not adversely impact the reliability of the nation's electric power system.

- Small entities with few units should be given additional time to comply with an EGU MACT rule's new requirements in order to account for their disadvantage in competing for equipment and skilled labor resources in a severely tight compliance timeframe. The electric utility industry, in general, will face great challenges in complying with an EGU MACT rule within the three year statutory deadline. Small cooperatives will find it even more difficult, if not impossible. Cooperatives, as a general rule, own few units and if stringent emission limits are imposed by an EGU MACT rule, utilities across the country will scramble to secure the equipment, contractors and skilled craftsmen needed to install the needed new control equipment. Large utilities have leverage to get their plans retrofitted first. Small cooperatives will find themselves at the end of a long line, making it highly unlikely that the new control equipment can be installed within three years. We strongly believe that the compliance deadline for small entities must be extended. Without specific compliance requirements to review, however, we cannot determine with specificity how much of an extension will be required. Similarly, specific units may not have the physical space to add the required controls equipment. Consideration must be given to alternative compliance methods for these units so that they will not be forced to shut down and be taken offline prematurely.

Conclusion

In conclusion, electric cooperatives remain concerned that EPA has not provided adequate time or provided rule alternatives or sufficient data to provide meaningful input on a rule of this magnitude and importance. The greatly foreshortened period for small business input on the EGU MACT rule is inconsistent with the stated goals of SBREFA to encourage the "effective participation" of small business in the federal regulatory process[6] and to create a more accommodating regulatory environment among agencies and small businesses that is less punitive and more solution oriented.[7] Section 609 of SBREFA envisions that the small business panel will review "any material the agency has prepared in connection with this chapter" including information required to be part of the initial regulatory flexibility analysis.[8] The regulatory flexibility analysis typically includes descriptions of significant alternatives to the proposed rule, differing compliance or reporting requirements or timetables that take into account the resources available to small entities, and the clarification, consolidation, or simplification of compliance and reporting requirements for small entities.[9]

The material presented by EPA at the one small business panel meeting does not address these issues of greatest importance to small entities. Hence, the ability of cooperatives to participate meaningfully in the small business review process has been seriously limited. We ask that EPA schedule additional panel meetings, once the agency has progressed further in its rulemaking preparation.

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[6] 5 U.S.C. Section 203(3).
[7] 5 U.S.C. Section 203(6).
[8] 5 U.S.C. Section 609(b)(4); *see also* 5 U.S.C. Section 603(b)(3), (4) and (5) and 603(c).
[9] *See* 5 U.S.C. Section 603(c).

If you have questions regarding any of the above, or need additional information, please do not hesitate to contact any one of the undersigned cooperative representatives. In the meantime, we urge the agency to seriously consider the cooperative concerns expressed above as it proceeds forward with this very important rulemaking.

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Rex Butler
Mngr., Environ. & Safety
Central Iowa Power Co-op
(319)366-4512 x 348
Rex.butler@cipco.net

\ S \

Leonard Hopkins
Fuel Procurement & Compliance Mngr.
So. Illinois Power Cooperative
(618)964-1448 x 268
lhopkins@sipower.org

\ S \

Joe Eutizi
Engineering Mngr.
San Miguel Electric Co-op
(830)784-3411 x 226
jeutizi@smeci.net

\ S \

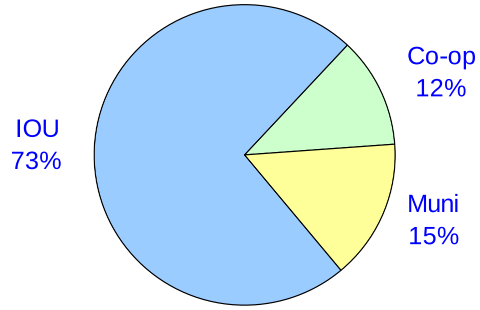
Mike Thatcher
Vice Pres. of Generation
Corn Belt Power Cooperative
(515)332-2571 x 7775
mike.thatcher@cbpower.coop

\ S \

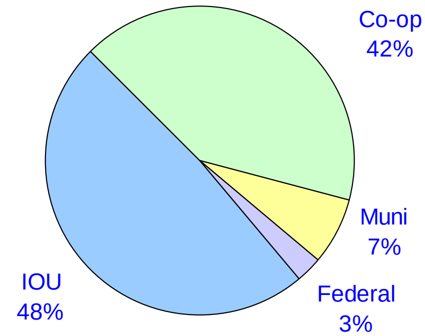
Bill Wemhoff
Sr. Principal, Environ. Policy
NRECA
(703) 907-5824
Bill.wemhoff@nreca.coop

Total U.S. Electric Utility Comparisons, by Sector

Customers

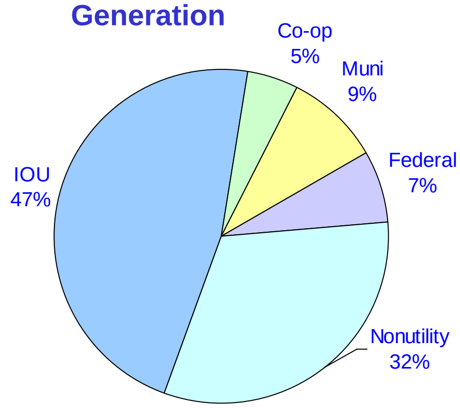


Distribution Miles of Line

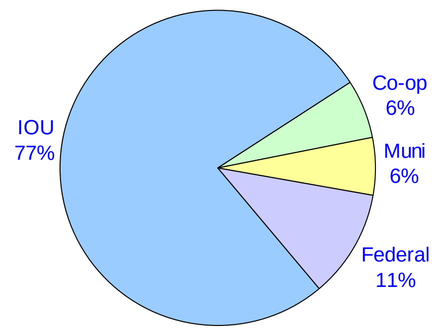


Investor-Owned (IOU)
Municipals (Muni)
Electric Co-ops (Co-op)

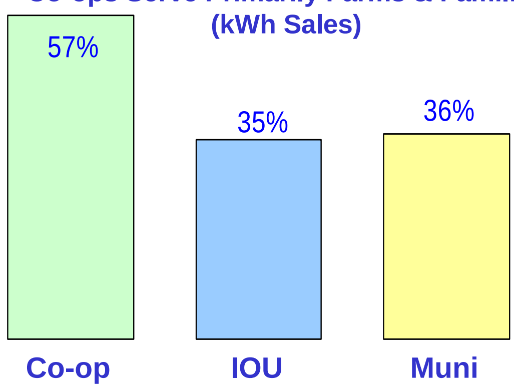
Generation



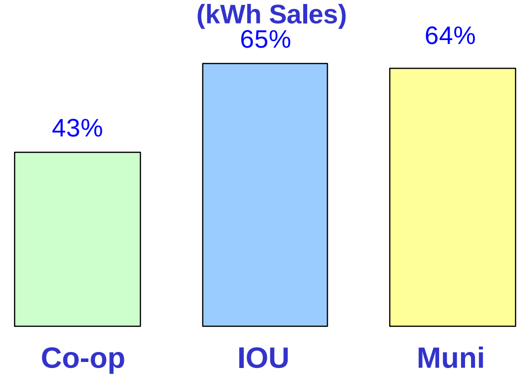
Transmission Miles of Line



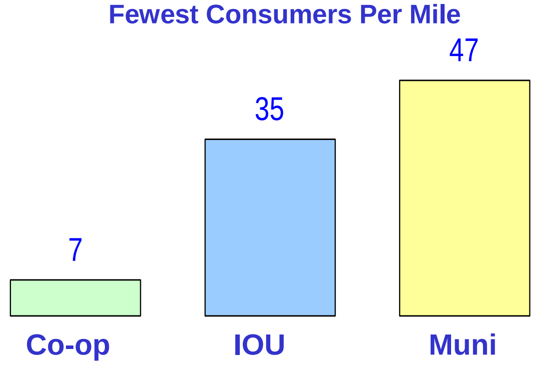
Co-ops Serve Primarily Farms & Families (kWh Sales)



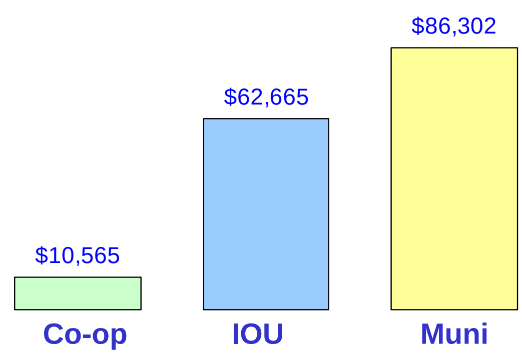
Other Utilities Serve Primarily Businesses (kWh Sales)



Co-ops Serve the Most Rural Areas & Have Fewest Consumers Per Mile



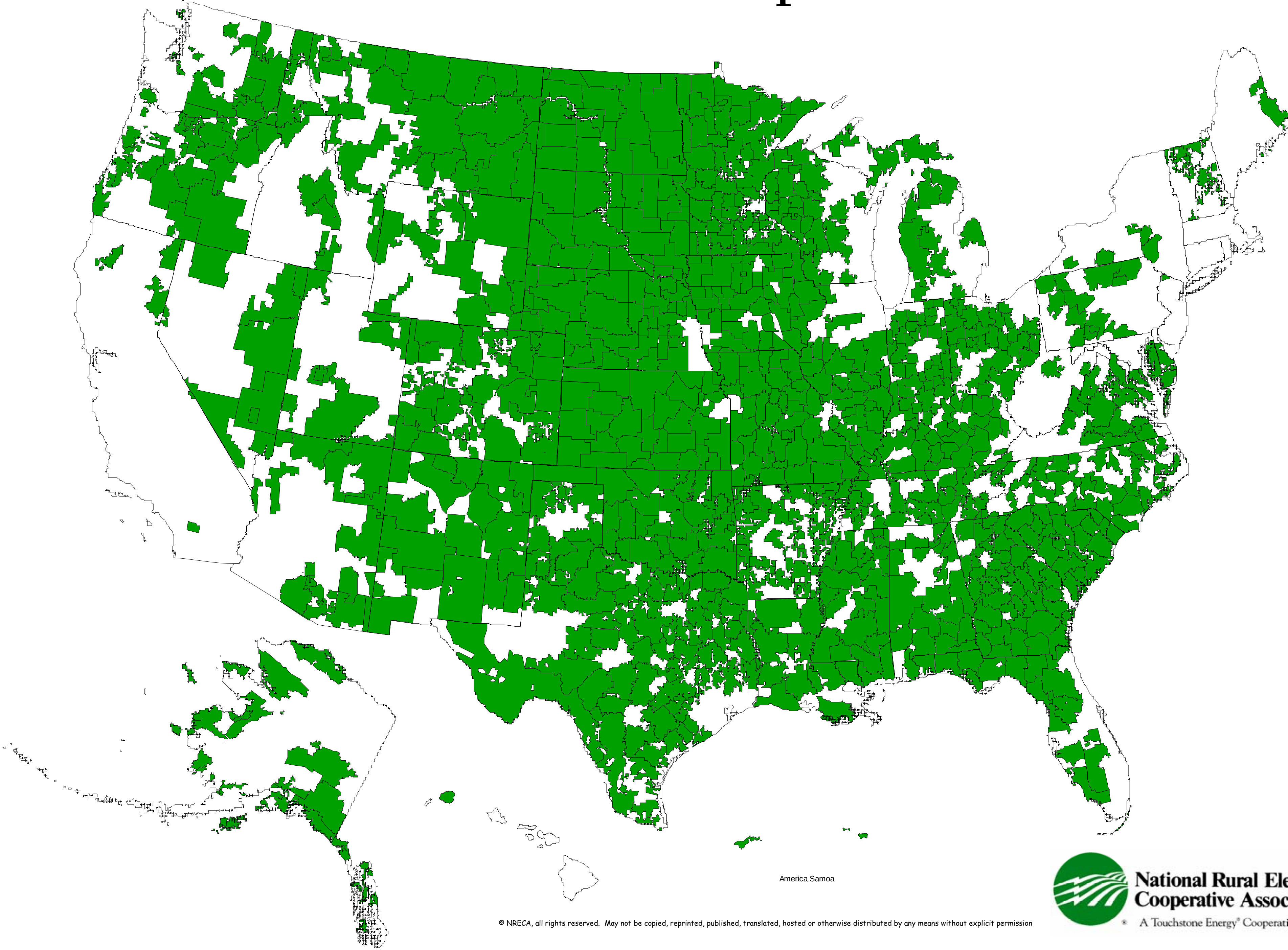
Co-ops Have Least Revenue Per Mile



Source: 2006 RUS/EIA data

NRECA Feb 2008

America’s Electric Cooperative Network



National Rural Electric Cooperative Association
A Touchstone Energy® Cooperative

APPENDIX "A"

EPA HAS UNDERESTIMATED THE NUMBER OF SMALL COOPERATIVES THAT WILL BE AFFECTED BY THIS RULE

In evaluating the small business impact of the EGU MACT Rulemaking, EPA must account for all potentially affected small cooperatives that qualify as "small entities."[1] In the material distributed by the agency prior to the December 2 meeting, EPA did not properly identify all generation and transmission (G&T) cooperatives that meet the Small Business Administration ("SBA") standards and did not recognize the relationship between G&Ts and distribution cooperatives.

Eighty percent of the electric power generated by cooperatives comes from coal-fired units. NRECA's 66 rural electric G&T cooperatives generate and transmit power to 668 of the 846 distribution cooperatives; 14 of these G&T cooperatives own coal-fired generation and qualify as "small entities" under the SBA size standards. 559 distribution cooperatives receive their electricity from G&T's that burn coal and also qualify as "small entities." The G&T cooperatives are owned by the very distribution companies they serve (virtually all of which qualify as "small entities"); the distribution cooperatives are owned by the consumers to whom they provide electricity. In fact, the Board of Directors for any given G&T cooperative is made up of either a member of the board or chief executive officer from each distribution cooperative that has an ownership stake in the G&T.

[1] The vast majority of NRECA's members meet the definition of "small" under the Small Business Regulatory Enforcement Fairness Act (SBREFA). Regulatory Flexibility Act (RFA), 5 U.S.C. §§ 601-612 (as amended Mar. 29, 1996). The RFA incorporates by reference the definition of "small entity" adopted by the Small Business Administration (SBA). The SBA's small business size regulations state that entities which provide electric services are "small entities" if they dispose of 4 million MWh or less per year. 13 C.F.R. §121.201, n.1.

In considering the economic impacts that the EGU MACT rulemaking would have on small electric utilities, EPA has identified 14 electric cooperatives nationwide that will be affected and that meet the SBA's small business standards. Of those identified, however, NRECA suggests that EPA's list includes some cooperatives that are larger than the SBA size standards and omits others that do meet the standards. Listed below are 14 coal burning G&Ts that NRECA believes should be included in any analysis of the impacts of the EGU MACT rulemaking on small entity cooperative G&Ts.

However, given the closely interwoven nature of the G&T cooperatives and the distribution cooperatives, it is clear that the EGU MACT rulemaking will have a direct impact on *all* electric cooperatives generating and/or distributing coal-based power. Any expenditure made by the G&T cooperatives in order to comply with the new regulatory requirements for the EGU MACT will be borne in tandem by the distribution cooperatives; to the extent that the G&T cooperatives can "pass through" their regulatory compliance costs, those costs are being passed *directly* to their consumer/owners – that is, to the distribution cooperatives. Because the G&Ts are owned by the distribution co-ops they serve, there are no third party shareholders who could help share these costs. And because the relationship between the distribution cooperative and their G&T is governed by an "All Requirements" contract, the distribution cooperative must receive its electricity from the G&T and there can be no market forces to moderate the price increases to consumers.

Also, EPA appears to believe that the "residential, commercial, industrial, and transportation sector economic demand for (*i.e.*, consumption of) electricity is relatively price inelastic, which suggests that electric utility plants may succeed in passing through most or all regulatory costs to their electricity customers." The reality is that these mechanisms do not operate for not-for-profit cooperatives. As explained above, there is no "market" for the electricity that distribution cooperatives receive from the G&Ts. Neither does the concept of "rate hike petitions to public utility commissions" readily transfer to the cooperative business model. G&T cooperatives deliver power to their members at cost-based rates determined by the Boards of the G&T, and the Boards are made up by representatives of the distribution cooperatives that own the G&T. All additional costs borne by the cooperative (and paid for by the distribution cooperative member-owners) affect the financial well-being of the G&T cooperative, rendering the discussion of a cost pass-through a moot issue for our members. The notion that "passing through" regulatory compliance costs to customers will somehow avoid or mitigate their impact does not apply to consumer-owned cooperatives. The business is the consumer and the consumer is the business.

The information presented in appendix "B" shows that distribution cooperatives have a higher percentage of residential consumers and those consumers use a higher percentage of electricity but have lower household income than the U.S. average. As cooperatives are forced to pass on the higher costs of power, these consumers will find it ever more difficult to pay for that power and may have to sacrifice other necessities. Furthermore, increasing cost of power has significant negative impacts on economic development and jobs in depressed rural areas.

<u>G&T Cooperatives that Qualify as Small Entities</u>

Sunflower Electric Power Cooperative
Square Butte Electric Cooperative
Northeast Texas Electric Cooperative
San Miguel Electric Cooperative, Inc.
Arizona Electric Power Cooperative, Inc.
Central Iowa Power Cooperative
Southern Illinois Power Cooperative
Kansas Electric Power Cooperative
Corn Belt Power Cooperative
Sam Rayburn G&T, Inc.
Prairie Power, Inc.
East Texas Electric Corporation
Northwest Power Cooperative
Power Resources Cooperative

America's Cooperative Electric Utilities
The Nation's Consumer Owned Electric Utility Network

Electric cooperatives are an integral part of the $364 billion U.S. electric utility industry. They play a critical role in our nation's economy and in local communities.

Electric cooperatives are:

- private independent electric utility businesses
- owned by the consumers they serve
- incorporated under the laws of the states in which they operate
- established to provide at-cost electric service
- governed by a board of directors elected from the membership, which sets policies and procedures that are implemented by the cooperatives' professional staff

Distribution cooperatives deliver electricity to the consumer. Generation and transmission cooperatives (G&Ts) generate and transmit electricity to distribution co-ops.

In addition to electric service, electric co-ops are involved in community development and revitalization projects, e.g., small business development, jobs creation, improvement of water and sewer systems and assistance in delivery of health care and educational services.

Facts at a Glance

- 864 distribution and 66 G&T cooperatives
- serve 42 million people in 47 states
- 18 million businesses, homes, schools, churches, farms, irrigation systems, and other establishments in 2,500 of 3,141 counties in the U.S.
- 12 percent of the nation's population are customers of rural electric co-ops

<u>To perform their mission, electric cooperatives:</u>

- own assets worth $112 billion (distribution and G&T co-ops combined)
- own and maintain 2.5 million miles, or 42%, of the nation's electric distribution lines, covering three quarters of the nation's landmass
- deliver 10 percent of the total kilowatt-hours sold in the U.S. each year
- generate nearly 5 percent of the total electricity produced in the U.S. each year
- employ 70,000 people in the U.S.
- retire $545 million in capital credits annually
- pay $1.4 billion in state and local taxes

Compared with other electric utilities:

- Co-ops serve an average of 7 consumers per mile of line and collect annual revenue of approximately $10,565 per mile of line
- Investor-owned utilities average 35 customers per mile of line and collect $62,665 per mile of line
- Publicly owned utilities, or municipals, average 46.6 consumers and collect $86,302 per mile of line

Cooperative Electric Utilities - Additional Facts

- G&T co-ops are owned and integrated with their member distribution co-ops.

- G&T co-ops generate approximately 50 percent of the electric energy they provide to their distribution co-op owners and purchase the remaining 50 percent in the wholesale market.

- Approximately 80% of co-op's self-generation is from coal-fired plants as compared to 45% for the electric utility industry.

- Nearly 60% of co-ops' kWh sales are to residential consumers. Other utilities (IOUs and Munis) serve primarily businesses. In comparison:
    - Only about 35% of IOU's (and 36% of Muni's) end-use sales are to residential consumers.
    - About 40% of co-op kWh sales are to commercial and industrial customers.
    - Commercial and industrial customers account for 65% and 64% percent of IOU and Muni kWh sales.

- The median co-op serves 12, 500 consumers compared to 400,000 consumers for IOUs.

- Co-op residential consumers also use more electricity – 35% and 20% more than residential consumers served by IOUs and municipals, respectively.

- Despite these barriers, the (median) co-op residential rate is only about 7.5% higher than their neighboring IOU.

- This challenge of higher residential rates, though, is amplified by relatively low household income in the rural communities served by co-ops – which is about 14% less than the U.S. average.

- Cooperatives are non-profit and operate "at cost" with no stockholders, all costs, therefore, that are borne by G&Ts must be passed on to distribution co-ops, and ultimately, end-use consumers.

- Because cooperatives have a disproportionate amount of coal-fired generation when compared to the electric utility industry as a whole, increases in costs of coal-fired generation could be disproportionately higher for cooperatives and their consumer-owners.

The National Rural Electric Cooperative Association

Comments On

National Emission Standards for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Proposed Rule 75 Fed. Reg. 32006 (June 4, 2010)

Submitted Electronically to:
The Environmental Protection Agency Air Docket
Attention: Docket ID No. EPA-HQ-OAR-2002-0058

August 23, 2010

Bill Wemhoff – Sr. Principal, Environmental Policy
(703) 907-5824 / bill.wemhoff@nreca.coop

4301 Wilson Boulevard, EU 11-249
Arlington, VA, 22203-1860

Introduction

The National Rural Electric Cooperative Association ("NRECA") offers the following comments on the U.S. Environmental Protection Agency's ("EPA" or "Agency") Proposed Rule: National Emission Standards for Major Sources; Industrial, Commercial, and Institutional Boilers and Process Heaters ("Ind. Boiler") or ("IB").[1]

NRECA has an interest in the outcome of this rulemaking. NRECA is the national service organization for more than 900 not-for-profit rural electric utilities that provide electric energy to approximately 42 million consumers in 47 states or 12 percent of the nation's population. Kilowatt-hour sales by rural electric cooperatives account for approximately 11 percent of all electric energy sold in the United States. NRECA members generate approximately 50 percent of the electric energy they sell and purchase the remaining 50 percent from non-NRECA members. The vast majority of NRECA members are not-for profit, consumer-owned cooperatives. NRECA's members also include approximately 66 generation and transmission ("G&T") cooperatives, which generate and transmit power to 668 of the 846 distribution cooperatives. The G&Ts are owned by the distribution cooperatives they serve. Remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. Both distribution and G&T cooperatives were formed to provide reliable electric service to their owner-members at the lowest reasonable cost.

NRECA's members and their consumer-owners operate and own industrial boilers and process heaters. Also importantly, EPA is developing maximum achievable control technology ("MACT") standards for electric utility steam generating units ("EGU") under the Clean Air Act ("CAA") Section 112(d) and has indicated in the information collection request ("ICR") for EGUs that it intends to follow a similar approach in setting MACT limits in that rulemaking as it has followed in the IB MACT rulemaking.

NRECA believes that finalization of rules to control emissions from these sources using the approach as proposed will result in increased costs that cooperatives, being not-for-profit, will be forced to pass along to their consumer-owners. Increased costs of electric power, particularly in rural areas served by cooperatives, have negative impacts on economic development and jobs.

[1] 75 *Fed. Reg*. 32006 (June 4, 2010)

NRECA urges the agency to include in its consideration the negative impacts of increased electric power costs as it finalizes its proposed rule.

NRECA is an active member of the Utility Air Regulatory Group ("UARG")[2] and fully supports the comments submitted by UARG in this rulemaking. UARG's comments include a more expansive discussion of many of the issues described below.

Summary

NRECA believes that the proposed standards are far more stringent than needed to assure protection of public health and the environment from industrial boiler hazardous air pollutant ("HAP") emissions. As explained below, EPA's approach to setting the standards is flawed and fundamental data issues exist that compromise the validity of the proposed standards.

NRECA also believes that EPA has both the need and the opportunity to make significant changes to the proposed standards. The agency has the legal discretion and the technical justification to substantially reduce the burden of the standards while still providing ample protection. NRECA provides recommendations in that regard in several key areas below.

Section 112 Standards Must Reflect the Emissions Control Achieved by Actual Units, Not Hypothetical Composite Ones

The proposed Ind. Boiler MACT limits were derived by determining independently a MACT floor for each HAP or HAP surrogate for each subcategory of sources. Under this approach, EPA identified the lowest emitting units[3] to determine the MACT floor for a given HAP. EPA then directs its attention to the next HAP, ignoring those units it just determined were the "best performing" in setting the MACT floor for the first HAP, and establishes the next MACT floor based on a different set of units. EPA repeats this process until MACT floors have been set for all HAPs emitted by each subcategory of industrial boilers. The end result is a set of MACT floors that

[2] UARG is a voluntary, nonprofit group of electric generating companies and organizations and four national trade associations (NRECA, the Edison Electric Institute, the American Public Power Association, and the National Mining Association). UARG's purpose is to participate collectively on behalf of its members in EPA rulemakings, related litigation, and other Clean Air Act proceedings that affect the interests of electric generators.

[3] In the case of new units, EPA bases the MACT floor on the best performing source.

do not represent the emission levels achieved by an *actual*, best-performing unit. Instead, they reflect the performance of a hypothetical, ideal unit that does not exist in the real world.

As UARG explains in more detail in its comments, Section 112(d)(3) of the CAA expressly requires that emissions limitation(s) for new units should not be less stringent "than the emissions control that is achieved in practice by the *best controlled similar source*." For existing units, the emission standards shall not be less stringent than the average emissions limitation achieved by the best performing 12 percent of *sources*.

NRECA believes that Congressional intent is clear that MACT standards promulgated under § 112(d) must be based on the actual performance of an actual source or sources. MACT standards are not to be based on hypothetical, ideal units nor do they allow the "emissions control" achieved by the best sources to be determined using a pollutant-by-pollutant approach on a shifting group of best performing units.

NRECA believes EPA's standard-setting approach violates the express language of § 112(d)(3) for setting new source MACT limits. New MACT source limits look to the level of performance "achieved in practice by the best controlled similar *source*." This language directs EPA to use a single "source" to set new source MACT limits. It does not direct EPA to use a collection of "sources" to set the lowest possible emission limit for each HAP for new sources. Similar logic applies for existing units because MACT standard setting is again premised on the performance of "sources."

As UARG describes in more detail in its comments, EPA's MACT standard-setting approach in the IB MACT rulemaking produces emission limits that fail to reflect the performance of actual sources. For example, in the biomass subcategory, the source with the lowest particulate matter ("PM") emissions had hydrogen chloride ("HCl") emissions that were over two orders of magnitude higher than the source with the lowest HCl emissions. Likewise, the source with the lowest mercury ("Hg") emissions had PM emissions 10 times greater than the best performing PM unit and 146 times higher than the best performing HCl unit.

EPA's approach for setting MACT floors in the proposed rule should not be used in the IB rulemaking and should not be used in subsequent § 112(d) rulemakings. MACT standards must be set based on the level of performance achieved by *actual sources*. EPA needs to develop a weighting approach for identifying the best performing units in MACT rulemakings where the sources in the category emit multiple HAPs and set the MACT standards based on the best performance by a single set of sources.

The Proposed Rule Fails to Address in a Reasoned Manner HAP Emissions That Are At or Below the Method Detection Limit

EPA‘s effort to set emission limits for all HAPs emitted by industrial boilers is greatly complicated by the fact than a number of HAPs are emitted at levels at or below the detection limit of the method that was used to collect and analyze HAP emissions during the IB MACT ICR. Detection limit issues have significant impacts on MACT standard setting as well as later during compliance demonstrations.

A discussion of detection limit issues must begin with a clear definitional framework for two important terms -- "detection limit" and "quantitation limit." The detection limit defines the threshold below which a test method cannot distinguish whether a substance is present or not. In EPA's prior efforts to implement the Clean Water Act, the agency defined the term "detection limit" to mean "the minimum concentration of an analyte (substance) that can be measured and reported with a 99 percent confidence that the analyte concentration is greater than zero." 40 *CFR* § 136.2(f). Stated differently, a measured value at the detection limit has an error band as large as the value being reported. One does not have great confidence in the quantity of material measured because the error band is so large; one simply knows it is more likely than not that the substance is actually present.

By contrast, the "quantitation limit" is the smallest detectable concentration of analyte greater than the detection limit where the accuracy, including both precision and bias, achieves the objectives of the intended purpose of the measurement. Target objectives are generally stated in terms of the precision of the measurement expressed as a relative standard deviation ("RSD"). There is no single agreed approach for determining the quantitation limit of a method. The quantitation limit for a given method can be three to 10 times higher than that method's detection limit depending on method-specific factors such as matrix effects and purity of reagents. One does not have confidence in the accuracy of a measured value unless that value is at or above the quantitation limit for the method.

Testing accuracy, reliability, and representativeness are vital in setting MACT standards because those limits must reflect the level of performance "achieved in practice" by the best performing units. They are also vital to permittees because test results, once they are sworn to be "accurate" on a monitoring report, are virtually unassailable in an enforcement action. Emission limits must not be set below the quantitation level of the method chosen for demonstrating compliance.

In the proposed IB MACT rule, EPA has established MACT emission limits based on reported detection limits. EPA's approach is flawed for several reasons. First, the agency failed to provide a clear and proper definition of detection limit in the IB ICR. As a result, the detection limits reported in the ICR responses are inconsistent and are not even based on a common understanding of the term "detection limit." It is likely that most IB owners seem to have reported the "detection limit" value they were provided by the laboratory analyzing the ICR samples. A cursory review of the ICR data shows that some "reported" values are actually below the detection limit values reported in other ICR tests. NRECA believes this could have been prevented if EPA had properly determined the detection limit for each method before issuing the IB ICR.

Second, EPA's focus on the method detection limit reported by a given laboratory ignores many sources of measurement error that can affect a reported result. Accuracy considerations are not limited to the ability of a single laboratory to precisely measure the amount of a substance in a given sample it receives. Measurement errors also occur during the collection of a sample at the stack, the transfer of that collected sample to whatever means are used to transport the sample to an analytical laboratory, and the interlaboratory inaccuracies of different laboratories testing the same sample. EPA's proposed rule does not address these areas of collection and analytical error. As a result, EPA's detection limit analysis is fatally flawed.

In its proposed rule, EPA has recognized some of the issues related to its use of detection limits (*See* 75 *Fed. Reg*. 32,020-21), and has requested comments on whether it should adjust the representative detection limit by applying a multiplier of three to account for measurement variability. While EPA's suggested adjustment is a step in the right direction, the remaining uncertainty is too large and therefore a larger multiplier is needed. More importantly, a method detection limit supplied by a given laboratory does not account for all sources of variability in sample collection nor interlaboratory variability in analyzing a given sample. EPA needs to address these issues in a comprehensive fashion prior to setting MACT standards in its final rule.

The Short Time EPA Took to Review the IB MACT ICR Data Has Resulted in Flawed MACT Standards

EPA's rush to comply with the unrealistic rulemaking schedule it agreed to in the IB MACT rulemaking has resulted in obvious and multiple flaws in the proposed MACT standards. EPA does not appear to have conducted its own quality assurance analysis of the ICR stack testing data. As UARG describes in its comments, even a cursory review of the IB MACT data by its consultant has revealed several important problems with EPA's analysis of the ICR data.

The fact that UARG was able to identify such obvious errors in a very limited review of the IB MACT database raises troubling questions about EPA's apparent blind acceptance of the IB ICR data given time limitations. EPA needs to conduct a thorough quality assurance review of the IB ICR data and only after that review repropose IB MACT limits.

The lesson for the upcoming EGU MACT rulemaking is that EPA must conduct a thorough analysis of the information it receives from its EGU ICR request. If more time is needed for EPA to perform a proper review, it must ask the court to revise the rulemaking schedule.

The Proposed Rule Fails to Account for All Variability in HAP Emissions

In order for a standard to be achievable, it must be achievable under most adverse circumstances which can reasonably be expected to recur. In order to assure that an emission limit is set at a level that the best performing source(s) will not violate, EPA must assess the variability in emissions of that unit.

In the proposed IB MACT rule, EPA has determined MACT floors based on a variability adjustment using an upper prediction limit ("UPL"). EPA's UPL equation attempts to identify an interval that will, with a specified degree of confidence, contain the next randomly selected observation from the population distribution. In theory, EPA's statistical analysis is reasonable provided the mean and standard deviations are computed from a distribution of values that reflect all operating conditions. Unfortunately for IBs, EPA lacks sufficient data to perform a meaningful UPL calculation.

As UARG explains more fully in its comments, EPA computes the within-source variance on the basis of three short-term (snapshot) tests. Three snapshot tests cannot possibly capture the level of performance that a unit will achieve "under the most adverse circumstances which can reasonably be expected to recur" -- the condition the D.C. Circuit has repeatedly said must be considered in setting MACT floors. Actual emissions variability for the best performing unit(s) results from a variety of factors, including different plant operating conditions, different control equipment settings, and different trace element constituents in the process raw materials. The fortuitous chance that each and every one of these variables would be present in the worst possible way for a short-term emissions test is miniscule, at best. The problem with EPA's variability adjustment is that it does not guarantee a proper assessment of the 99th percentile performance of a given unit if the emissions data from three days of testing of that unit are not representative of all the unit's operating conditions over an extended period of operation. The three ICR test runs for each boiler were performed hours apart and most likely under identical operating conditions. As a result, EPA lacks the data needed to determine whether the best performing units could ever perform as well as they did during the ICR testing.

The lesson for future MACT rulemakings is that if EPA fails to obtain a complete picture of operating conditions of the best performing units over a sufficiently extended period of time, it cannot hope to develop an accurate assessment of the level of performance those plants will achieve under the worst reasonably foreseeable circumstances. No amount of statistical hand-waving can solve a lack of appropriate data.

EPA Needs to Consider Additional Subcategories for Industrial Boilers

Section 112(d)(1) of the CAA allows the Administrator to distinguish among "classes, types, and sizes of sources" in establishing MACT standards. This subcategorization language mirrors earlier language found in CAA § 111. In providing EPA discretion to create subcategories, § 112(d)(1) does not restrict subcategorization to cases where the "class," "type" or "size" factors affect HAP emissions. The provision merely requires EPA to establish regulations for each category or subcategory on the schedules set out in § 112. Indeed, EPA has not previously subcategorized under § 111 based solely on emission effects. For example, under § 111 EPA has subcategorized boilers on the basis of size (heat input) or the type of fuel burned (coal, oil or gas). These subcategorization decisions were based on feasibility and/or cost considerations, not on the level of emissions.

NRECA commends EPA for creating a large number of subcategories in the proposed IB MACT rule. However, NRECA believes EPA should have created even more subcategories.

Historical testing has shown that coal rank has a significant effect on Hg and HCl emissions. Also, as discussed below, a limited use subcategory should be created for IBs that are operated infrequently because of their specialized nature and use.

EPA Should Use Section 112(d)(4) Whenever Appropriate in Setting Emission Limits

EPA has requested comments on whether it should impose a health-based standard under § 112(d)(4) for HCl and other acid gas emissions from IBs. Section 112(d)(4) is designed to prevent the promulgation of unduly stringent emission limits simply for the sake of regulation. Section 112(d)(4) allows EPA to set health-based limits for certain HAPs based on established health thresholds, rather than having to follow the technology forcing provisions of § 112(d)(3). As a practical matter, § 112(d)(4) applies to non-carcinogenic HAP for which EPA has established a health threshold such as a reference concentration ("RfC") or a reference dose ("RfD"). EPA defines a reference concentration in its IRIS database as "[a]n estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime."[4] Thus, human exposures to a HAP at levels below its RfC are considered "safe," particularly given the uncertainty factors that EPA includes as part of its derivation of a RfC.

Section § 112(d)(4)'s inclusion in the 1990 CAA Amendments indicates a Congressional intent to retain the health endpoint of the original § 112 -- protection of public health with an ample margin of safety. If the emissions of a given HAP from all sources in a source category are at a level where public health is protected with an ample margin of safety, then there is no practical need for or benefit from further regulation. NRECA encourages EPA to set health-base standards under § 112(d)(4) when facts support its use.

MACT Limits Should Be Based on Emission Limitations Achieved by No Fewer Than Five Units

In the proposed IB MACT rule, EPA has based the MACT floor for certain subcategories on emissions data from less than five sources even though the subcategory contains more than 30

[4] The definition for a reference dose is essentially the same except it focuses exposure by pathways other than inhalation.

units. EPA has requested comments on whether it should set existing source MACT limits based on the emissions of at least five "best performing" units in larger subcategories (more than 30 units) when only limited emissions data are available. NRECA believes it should.

The CAA requires EPA to set MACT limits for existing sources based on "the average emissions limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emission information)." For source categories with less than 30 sources, existing source MACT floors are to be set based on "the average emission limitation achieved by the best performing 5 sources (for which the Administrator has or could reasonably obtain emissions information)." NRECA believes these two provisions indicate that Congress intended MACT standards to be set on a no less than five "best performing" units. It is fair to assume that Congress never contemplated the situation were the amount of available data from a large source category or subcategory would require EPA to set MACT limits based on the performance of only one or two sources.

HAP Emissions During Startup and Shutdown Should Not Be Treated the Same as HAP Emissions During Normal Operations

The IB ICR did not require any testing during start-up, shutdown and malfunction events. Without emissions data during these periods, EPA has absolutely no factual basis for concluding that the best performing units can achieve the proposed MACT limits during these events. For example, operations during boiler start-ups are different than normal plant operations. Certain plant components must be started in a specific sequence in order to ensure that steady state operations can be achieved. During start-up not all pieces of control equipment will be operating at peak efficiency. NRECA believes work practices standards are far more appropriate during these periods. Similarly, for the same reasons, work practice standards are also more appropriate for shutdown and malfunction events.

If EPA insists, however, on setting emission limits for these periods of operation then the agency must obtain emission data during these periods of operation and properly analyze those data in order to set MACT emission limits.

Also, NRECA is concerned about the potential for enforcement of operating parameter and opacity limits during periods of startup, shutdown, and in the event of equipment malfunction. When EPA finalized its rule in 2004 with enforceable operating parameters, it did so with a rule that also made clear that those limits did not apply during periods of "startup, shutdown, and malfunction." 40 *C.F.R.* § 63.7505(a), 69 *Fed. Reg.* at 55,254. EPA's current proposal contains no such exception, but instead would allow enforcement of deviations from operating parameters during these periods, when controls would not be expected to be operating at the same levels as during performance tests, and due solely to equipment malfunctions. In its proposed rule, EPA asserts that it has taken startup and shutdown periods into account by using continuous emissions monitoring system ("CEMS") data from best performing units that include periods of startup and shutdown, and by proposing use of "daily or monthly averages." Regarding malfunctions, EPA asserts that it would use a variety of information to determine an appropriate response to exceedance caused by equipment malfunction.

NRECA believes EPA's assertions regarding startup and shutdown are inapplicable to control device operating parameter limits, which are based on 12-hour averages (not daily or monthly averages) established during performance test (not based on CEMS data that include startup and shutdown). Even a daily block average, as proposed for opacity, does not provide sufficient protection if the unit does not startup or shutdown at exactly midnight, since there might not be sufficient data under normal operating conditions to compensate for the startup or shutdown period. In short, NRECA believes EPA has not made sufficient allowance in its rules for periods of startup and shutdown. To the contrary, EPA has proposed to require sources to establish control device operating parameter levels that are dependent upon load during periods of "maximum normal operating load," and then maintain those levels during periods other than maximum normal operating load, including startup and shutdown. NRECA thinks EPA's proposal is unreasonable and the agency must address these periods by allowing sources to identify alternative parameters or by establishing simple work practice standards for these periods.

EPA's promise to address periods of equipment malfunction by considering other information before enforcing exceedance of operating limits also provides little comfort, especially given the risk of citizen suits. Although NRECA appreciates EPA's proposal to make clear that "deviations" of operating limits are not necessarily violations, nothing in EPA's proposal would prevent EPA, a state, or a plaintiff in a citizen suit from simply determining in their "discretion" that any particular exceedance constitutes a violation. MACT standards are technology-based standards, and NRECA believes the agency must recognize that even the best performing technology occasionally fails.

The Facility Averaging Provisions Should be Modified

The proposed IB MACT rule allows emission averaging in certain circumstances. While emission averaging can, in theory, provide operational flexibility to sources, the emission averaging provisions of the proposed rule are so restrictive and highly conditioned that they are unlikely to be used. The proposed rule would apply a 10 percent "discount factor" on any source seeking to average emissions across units at a facility. This discount factor will deter averaging. As noted elsewhere in these comments, EPA's proposed IB MACT standards are so low that there are real questions about whether sources can even comply with them using state-of-the-art control equipment. By effectively lowering those standards further by 10 percent for sources that average emissions, it makes an impossible situation even more impossible. Also, there is no legitimate reason for imposing a 10 percent penalty on sources that seek to average emissions. Total emissions from a single facility have the same health effects on public health regardless of whether each unit at the facility meets the MACT limits or all units meet the MACT limits in the aggregate -- the total emissions from the facility are the same. The 10 percent penalty on operational flexibility has *no* public heath benefit.

Other onerous provisions in EPA's proposed averaging program include the detailed averaging plan a facility would need to prepare and the cap on unit emissions would not allow any unit participating in the averaging to have emission any higher then it had on the effective date of the proposed rule. If EPA is serious about providing operational flexibility to facilities, then it must make substantial revisions to its proposed averaging provisions.

Biomass Limits Are Flawed and Will Impede the Construction of EGU Biomass Units

As a matter of public policy, EPA should encourage the combustion of biomass as substitute fuel for coal or oil. The combustion of biomass will become increasingly important to utilities as renewable energy standards are adopted by more states and are possibly applied to all states as a result of federal mandates. The combustion of biomass has the beneficial effect of conserving natural resources. Unfortunately, the stringent MACT limits EPA has proposed for IBs burning biomass will greatly inhibit the combustion of biomass in the future.

The proposed biomass emission limits are exceedingly low because of errors in standard-setting discussed above. The PM limit for biomass units does not account for fuel-related variability. PM emissions are directly related to the ash content of a fuel. The ash content of unadulterated wood is highly variable. Similarly, EPA does not appear to have made any fuel-related adjustments for chlorides or Hg in biomass.

EPA Should Promulgate Work Practice Standards for Utility Auxiliary Boilers and Expand the Practice to All Gas-Fired Units

Electric utilities that operate auxiliary boilers will be subject to the IB MACT rule because they are not steam generating units that produce electricity. Auxiliary boilers operate infrequently, normally during plant start-ups, and combust either natural gas or distillate fuel. As a result, the HAP emissions from the auxiliary boilers are exceedingly low and do not pose any risk to public health.

Under the proposed rule, gas-fired auxiliary boilers are subject to work practice standards requiring an annual tune up. NRECA supports EPA's decision to set a work practice standard for this group of gas-fired IBs. The HAP emissions from these units are so low they are impossible to measure accurately. Furthermore, these vanishingly small emissions do not pose risks to public health and the cost of controlling emissions from these units dwarfs whatever minute benefits may result.

This work practice standard should be extended to IB units burning coal-derived gas. Utilities are increasingly being asked to consider constructing integrated gas combined cycle ("IGCC") units. These units include a coal gasifier that produces gas for later combustion in a gas turbine. The gas from an IGCC unit is cleaned prior to combustion so in terms of trace HAPs it is little different than natural gas or refinery gas. NRECA believes EPA should add coal-derived gas to the fuels in the Gas 1 category.

By contrast, the proposed IB MACT rule requires oil-fired auxiliary boilers to comply with stringent emission limits and demonstrate compliance with those limits by following expensive monitoring requirements. The distinction between these two different types of auxiliary boilers is unnecessary and does not produce environmental benefits.

NRECA also believes EPA should create a limited use subcategory for boilers combusting distillate fuel that would subject those units to the same work practice standards as gas-fired units. The limited use subcategory should have a 10 percent capacity factor threshold. Eligibility for this subcategory would be determined based on 10 percent of the maximum hourly heat input of the boiler multiplied by 8,760 hours per year. Providing a limited use category with the limitations described above, would not pose any risk to human health but would provide substantial economic and administrative relief to owners of these sources.

Proposed Compliance Demonstration Provisions

EPA proposes several compliance demonstration methods depending upon the size of the unit and whether controls are required to meet the proposed limit. UARG includes in its comments extensive discussion regarding various issues and concerns regarding EPA's proposed compliance provisions. NRECA supports UARG's comments and also makes the following key points:

- NRECA supports the use of stack testing and the fuel analysis option for Hg and HCl, but as described in detail in UARG's comments, is concerned with EPA's proposed implementing rules. NRECA has concerns regarding the use of carbon monoxide ("CO") CEMS to make compliance determinations at some of the proposed emission limits, and has objections to EPA's proposed use of PM CEMS.
- NRECA does not object to EPA's general approach of using operating parameters to assure compliance in between stack tests. EPA has previously used this approach in the Compliance Assurance Monitoring (CAM) rule to assure continuous compliance with standards that do not already specify continuous compliance methods. NRECA does object, however, to EPA's proposed use of operating parameters as enforceable limits, and questions the achievability of the proposed 10 percent opacity standard, particularly in the absence of any exception for startup, shutdown, or malfunction. NRECA also objects to several provisions related to proposed bag leak detection systems and the lack of clarity in EPA's proposed requirements for periodic fuel analysis.
- NRECA generally supports EPA's proposal to use periodic performance tests, rather than CEMS, as the primary method for determining compliance with

emission limits when limits cannot be met based on fuel analysis. NRECA believes that such periodic tests will ensure on an ongoing basis that the air pollution control device is operating properly and its performance has not deteriorated. NRECA also supports EPA's proposal for reduced periodic testing, but objects to the restrictions EPA would impose. In addition, NRECA suggests that EPA provide options for use of several additional well established test methods not included in the proposed rule, and other options that would allow for reduced run length when appropriate.

- NRECA supports the option to use fuel analysis to demonstrate compliance where possible, and does not object to a requirement to perform a new fuel analysis for Hg and chlorine when a new fuel is combusted. However, NRECA does not support EPA's proposed requirement for monthly fuel analysis for sources that have not changed fuel type, or the agency's proposal regarding how that analysis is used.

Proposed Recordkeeping and Reporting Requirements

The proposed rule includes a multitude of recordkeeping and reporting requirements. NRECA believes many of these requirements are not sufficiently justified and will impose unreasonable costs. Specifically, NRECA objects to EPA's proposed requirement to report using the electronic reporting tool ("ERT") and disagrees with EPA's assertions regarding the impact of that requirement on reporting and on emission factor development. As UARG notes in its comments, while experience with the ERT has been limited, industry nonetheless has identified a number of shortcomings in the programs. Furthermore, use of ERT is burdensome (easily adding 10-20 percent to the cost of compliance testing), requiring manual inputting of significant amounts of information much of which is not relevant to performance test results. It also is subject to significant performance issues, including software crashes and shutdowns, inoperable features (like report generation), and inadequate identification of errors preventing data analysis. In short, even if EPA can justify a requirement to report performance test data electronically, EPA cannot justify requiring sources to use this program.

The Recordkeeping and Reporting Provisions Are Overly Burdensome

EPA's proposal includes requirements for the tracking of numerous data points, including fuel consumption; operating hours, startups, shutdowns including dates and times; equipment malfunctions including dates and times; numerous operating parameters including dates and times of deviations; CEMS, COMS, and CPMS calibration and quality assurance/quality control data; CEMS, COMS and CPMS maintenance information; CEMS, COMS, and CPMS out of control periods including reasons, dates and times; performance test reports; fuel sampling reports; vendor reports; and a number of other pieces of information. Records must be kept of virtually all information referenced in the proposal, including all CPMS data required to be collected, for five years. Unfortunately, much of these data gathering requirements cannot be automated, but instead will have to be collected manually. Once the data are gathered, decisions will have to be made regarding what has to be reported and a report will have to be generated and certified. This will be a massive undertaking and the possibility of making an error during the process will be a virtual certainty.

To reduce manpower requirements most sources will likely attempt to automate as much of the reporting and record keeping as possible. The equipment costs alone for implementing an automated (to the extent possible) data collection and report generation system for a unit with multiple controls is likely to be very high and there may be little opportunity for standardization of the software. In short, NRECA does not believe that EPA, in proposing its enforceable *operating limit* approach, has adequately estimated or considered the data management costs of its proposal and requests that the agency do so.

Conclusion

In conclusion, NRECA believes EPA's proposed approach to setting MACT standards is flawed and will result in standards that reflect the performance of a hypothetical, ideal unit that does not exist in the real world. The emission limits are far more stringent than needed to assure protection of public health and the environment, and may not be achievable by actual sources.

The agency has failed to appropriately address emissions that are below the detection limits, failed to account for variability in HAP emissions, and has inappropriately established standards below the quantitation limits. There are real questions regarding whether sources can even comply with these low limits as well as how they will meet the requirements for compliance demonstrations. Furthermore, NRECA has many concerns regarding the proposed compliance demonstration provisions and believes that the recordkeeping and reporting provisions are overly burdensome.

Finally, NRECA urges the agency to consider additional subcategories of sources, to promulgate work practice standards for utility auxiliary boilers, and set standards for biomass-fired electric generating units that do not impede the construction of new units.

NRECA appreciates the opportunity to provide comments on this important rulemaking and would be happy to answer any questions EPA may have regarding these comments, or provide to the agency additional information that it may desire.