NMA
THE AMERICAN RESOURCE

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<u>Via Electronic and Hand Delivery</u>

EPA Docket Center (Air Docket)
U.S. EPA West
Room B-108
1301 Constitution Avenue, N.W.
Washington, DC 20460

Attn: Docket ID No. OAR-2002-0056

Re: 40 CFR Parts 60 and 63
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 FR 4652 *et seq*., January 30, 2004

Ladies & gentlemen:

The National Mining Association ("NMA") takes this opportunity to comment on the above-styled proposed rulemaking. These comments are supplemental to NMA's comments filed May 14, 2004.

These comments are organized as follows:

I) Mercury removal technologies - their relationship to the rulemaking, and NMA's proposed alternative

II) NMA's support for, and further clarification of, the comments submitted by the Utility Air Regulatory Group (UARG), of which NMA is a member.

I) Mercury removal technologies - their relationship to the rulemaking, and NMA's proposed alternative

One of the issues affecting the determination of emission limits or allowance allocations in a mercury rule is the availability of technology for mercury control. In general, there are two options for mercury control. First, some mercury can be removed (as a "co-benefit") by existing equipment installed for particulate, NOx and SO2 control. Second, new technology specifically designed to remove mercury for installation on existing or new facilities is still in development. Generally, the mercury-specific technologies fall into two categories. The first category includes technologies intended to enhance the ability of existing emission control devices to capture mercury. An example is the injection of an additive into a furnace or flue gas to enhance oxidation of mercury to increase its removal in a wet scrubber. The second category includes the use of materials placed in or injected into the flue gas for the purpose of capturing mercury. The most prominent example is the injection of activated carbon (ACI) ahead of a particulate collection device.

Mercury Co-benefit Technology

Co-benefit technology for mercury removal can be considered to be commercial, to the extent the equipment itself (principally SCR, scrubber, ESP, and fabric filter technologies) is in widespread commercial use. However, because these technologies were not designed and operated specifically for mercury capture, it is impossible to know, with an acceptable level of certainty, what their performance is for mercury control for any specific unit, burning any specific coal. This uncertainty is best understood through an analysis of the data on mercury emissions from existing sources. The performance of co-benefit technology was characterized in the EPA ICR Part III sampling of mercury emissions from power plants. As discussed in NMA's May 14 comments on the mercury rule, the ICR Part III emissions data are fraught with error and uncertainty, and are inadequate to determine variability in emissions for a single unit, or among units utilizing similar technology. This makes it impossible to determine the performance of co-benefit technology for specific units with a high degree of confidence. The issue of projecting co-benefit mercury removal is discussed by Chu and Offen[1] of the Electric Power Research Institute, who observe that, while co-benefits reductions are likely, the level of reduction is variable. Unresolved questions include the efficacy of different FGD designs, performance with different coals, the effect of SCR catalyst age, and of catalyst type and design under variable flue gas conditions. An aggregate estimate of emissions from all sources may have somewhat higher accuracy through the effect of averaging, but with a very wide confidence interval.

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[1] Paul Chu and George Offen, "Mercury Emissions and Controls – Issues and Paths to Resolution," Environment Multimedia Workshop, Monterey, CA, February 2, 2004. (Attachment I)

Challenges Facing Developing Technology

A fundamental problem in developing and predicting the performance of mercury control technology is that mercury chemistry is poorly understood, particularly in context to the wide range of conditions encountered in coal-fired power plants. Correlations of mercury speciation with flue gas composition are instructive, but have poor predictive power (i.e., wide confidence intervals) as discussed in NMA's May 14 comments on the rule. These numerical correlations fail to account for such important factors as flue gas and fly ash composition, including unburned carbon, and heterogeneous gas-solid reactions between mercury and the fly ash[2]. Work on scientifically based (i.e., a priori) chemical models is underway, but their usefulness remains to be seen.

Another factor affecting the development of mercury control technology is simply the difficulty in obtaining accurate mercury concentration and emission data. While continuous emission monitors (CEMs) for mercury are under development, most of the mercury emissions data to date, and all the ICR Part III data, were obtained using the Ontario Hydro method, a complicated, multi-step sampling and analysis method with a relative precision no better than ±20%. The ASTM repeatability and reproducibility standards for the mercury-in-coal measurement have about the same relative precision. Such a high degree of experimental uncertainty increases the difficulty in separating responses to significant variables from random variation. Note that, even with these wide precision ranges, much of the ICR Part III emissions data fell outside of experimental control, demonstrating that systematic measurement error adds further uncertainty to experimental results.

Department of Energy Research, Development and Demonstration Program Status

Mercury-specific technology for coal-fired power plants has yet to be installed commercially. Promising control options have been identified, and some full-scale tests are underway. The status of developing technology is described in a recent presentation by T. J. Feeley of the U. S. Department of Energy.[3] DOE is the principal sponsor of mercury technology development in the U. S. A copy of the presentation is appended to these comments (Attachment II).

As Feeley reports, DOE's mercury research began in the early 1990s. The early work was done principally to support EPA in meeting the requirements of the Clean Air Act Amendments of 1990 for a report to Congress on Hazardous Air Pollutant (HAP) emissions from power plants. At the time, very little was known

[2] Chu and Offen

[3] Thomas J. Feeley III, "DOE-NETL's Mercury Control Technology R&D Program for Coal-Fired Power Plants," Mercury Emissions from Coal 1st International Experts' Workshop, Glasgow, Scotland, May 12-13, 2004.

about HAP emissions from power plants, and the methodologies for measuring them accurately were largely non-existent. Specifically, methods for measuring mercury at the exceptionally low concentrations found in coal and to make speciated mercury measurements in flue gas were just being developed. Therefore, much of the early effort was concentrated on making emission measurements from a few sources while refining the measurement methods. Exploratory, bench and pilot research on mercury control technology was begun in the mid- to late-1990s, with initial ("Phase I") field tests conducted by late 2002. These consisted of short-term tests of carbon injection at four sites, and tests of enhanced scrubbing at two sites.

On the basis of the Phase I tests, DOE concluded that ACI "works," but that its effectiveness depends on coal type and plant configuration. The enhanced scrubbing tests also showed some positive results, but questions remained about the effects of wet scrubber size and chemistry on the conversion of oxidized mercury and re-emission of elemental mercury, a phenomenon commonly observed in mercury emission measurements at wet scrubbers. DOE identified a number of significant uncertainties, including performance over longer periods of operation, capture effectiveness with different coals, sorbent feed rate and costs, FGD Hg reduction/re-emission, by-product use and disposal, the potential need to install fabric filter for units equipped with ESPs, and balance-of-plant impacts.

To begin to resolve these uncertainties, DOE initiated additional field tests in 2003. These included the only long-term test of mercury control by ACI to date, which was done at the Southern Company Gaston Plant. The Gaston plant is unusual for coal-fired boilers because it is equipped with a baghouse located downstream of its ESP. The baghouse had been installed for particulate control, in what is known as the COHPAC configuration. DOE also initiated a project to measure mercury emissions at 10 SCR/FGD equipped units to gain better information on the level and variability of performance of this technology combination for mercury control. Although in its modeling EPA appears to count heavily on SCR/FGD combinations for mercury cobenefit removal, no SCR/FGD unit was included in the ICR Part III tests. Relatively few SCR/FGD tests of mercury removal have been done since then, with tests on subbituminous and lignite coal units being particularly lacking.

In September 2003, DOE selected eight projects for funding under Phase II of its mercury field test program. These projects, which began in the Spring of 2004 and will be completed in 2006, include both sorbent injection and enhanced mercury oxidation technologies. As detailed on page 24 of the DOE presentation[4], the Phase II program involves tests of seven different technologies at 16 units. These tests will provide important information on the performance of a range of technologies with a number of coals. While "longer term" than most of the Phase I projects, none of these projects is designed primarily as a long-term

[4] Feeley at 24.

test. In April 2004, DOE accepted proposals for additional Phase II tests, focusing its interest on low-rank coals and blends, which will continue into 2007. One full-scale mercury control project was selected for award under the DOE Clean Coal Power Initiative (CCPI) program. This CCPI project is scheduled for completion in 2007. DOE anticipates a Phase III of mercury control technology testing to begin in 2006, and be completed some time after 2010. As slide 10 of the DOE presentation depicts, the goal is to have these technologies ready for commercial demonstration some time after 2010. While the specifics of the commercial demonstrations are not spelled out in the DOE plan, clearly it will take several years to allow sufficient operating time on a number of installations to bring these technologies beyond demonstration status.

"Commercially Available" Control Technology

Commercial technologies, as distinguished from those that are still in development, must be able to control mercury emissions from plants burning a range of coals differing in rank, sulfur and chlorine content, ash composition, etc. Proven commercial technologies must perform in a predictable manner when used with boilers of various designs over the range of operating conditions that the plant will encounter. Short-term field tests or demonstration projects are not sufficient to conclude that a technology is commercially available.

Furthermore, a technology is not commercially acceptable just because a vendor is willing to sell it or even to offer some level of performance guarantee. The key is that power companies must (a) provide electricity when a customer flips a switch and (b) must subject their investment decisions to the Public Utilities Commissions (PUC) review (for regulated utilities, which are still the majority, at least among coal-fired plants) or to shareholders and the financial institutions for investor owned utilities. To meet these investment thresholds, the generator must be able to present evidence of sufficient experience with the technology (e.g., demonstrations at sites where it's not mandatory to meet an emission limit) that they can be assured the equipment will perform as predicted and be reliable on their units/coals. Guarantees provided by vendors can help the utilities partially recover the cost of the equipment if it fails to perform to specifications, but guarantees will not help them recover lost generation and its financial consequences. Vendors will ordinarily insist on a liability limit that is generally the total value of the order. Consequential damages such as the value of lost generation are always excluded from the warranty. The maximum payout will commonly be the cost to repair or replace a defect "part" and is far less then the cost of the equipment sold and, in the case of environmental projects, certainly less than the losses suffered due to the inability to comply with emission limits. The short time frame proposed until power companies will need to comply further compounds this. As a result, many plants may be forced to install unproven equipment just before their compliance deadline. These units will need to be derated or shut down if the mercury control equipment does not meet the guaranteed performance. Therefore confidence in the performance of the technology as demonstrated by long-term operation under a variety of circumstances is critical to accepting it as commercial.

Activated Carbon Injection

An argument has been put forward that because activated carbon injection is being used currently to remove mercury from flue gases from municipal, medical, and hazardous waste incinerators, it should be viewed as commercial technology for power plant application. However, the incinerator application cannot be directly related to coal-fired power plant emissions because the mercury in the flue gas associated with power plants is much less concentrated than mercury emissions from incinerators. For example, the federal standard for mercury emissions from medical waste incinerators (MWI) is 0.55 mg/dscm or, alternatively, at least an 85% reduction. To put that in perspective, the mercury concentration in the flue gas for a typical coal-fired boiler is 0.01 mg/dscm, or a factor of 55 less than the permitted emission level for the MWI. EPA's proposed MACT for bituminous coal would require about a 75% reduction in mercury emissions from the average coal, resulting in a mercury concentration in the flue gas of 0.0025 mg/dscm. That corresponds to a reduction of 99.6% below the level of emissions permitted from the MWI. Put another way, it would require an MWI to achieve 99.93% mercury capture (rather than the 85% alternative standard allowed by EPA) to achieve the same mercury emission rate as the coal-fired boiler. The reason this is particularly relevant is that bulk gas-phase mass transfer is a limiting factor for mercury removal by sorbent injection. That is, there must be sufficient time for mercury in the flue gas to migrate to the sorbent particle surface and be absorbed. Lower mercury concentrations require greater time or proportionally more sorbent to overcome this physical limitation. Given the vastly greater concentration of mercury in combustion gases from incineration sources, the experience with carbon injection on those units is of limited value for setting emission standards from coal-fired units.

An MWI also has a higher chlorine concentration in its combustion flue gas which results in a higher concentration of more easily removable oxidized mercury. Such capability means that there is less elemental mercury removal needed. This is not the case for utility systems that have higher concentrations of elemental mercury (1999 ICR data indicated that most mercury emitted was in the elemental form) but in lower concentrations. Utility systems also operate at higher temperatures, which is a significant factor in the efficacy of activated carbon to remove mercury from the flue gas. For some coal-fired boilers, such as lignite units, which operate at the highest of utility system temperatures, activated carbon injection is completely ineffective.

Emission Control Retrofits

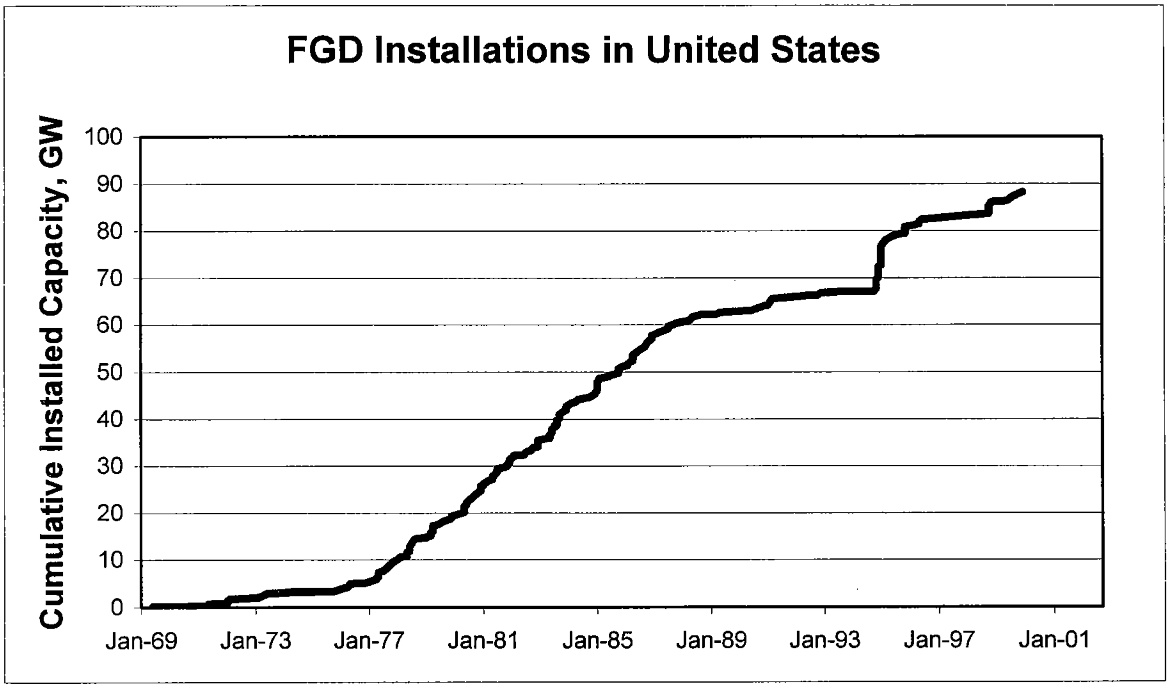
To the extent that cobenefit (or enhanced cobenefit) reduction is not adequate to meet the standard, mercury-specific retrofit technology will have to be installed on existing plants. The sites for the tests done to date were selected, at least in part, because of the ease of retrofit application of the control equipment (i.e. they were not confounded by space limitations typical of most retrofit applications), or because an enhanced particulate control system was already being utilized – situations that are not typical of the population that would be subject to retrofit controls. For example, as noted above the Gaston plant was chosen because it had an existing COHPAC system. All of the tests in DOE's Phase I testing were done on units with oversized ESPs, which provide additional time for reaction of mercury with the sorbent, while minimizing the potential impact of sorbent injection on particulate emissions. In one test, sorbent was injected into only one field of a four-field ESP to reduce retrofit difficulties. Space ("footprint") limitation can be a significant factor in the potential application of back-end technology to existing units, particularly for older units that already have installed retrofit particulate, NOx, and FGD devices. A unit may have an inadequate length of duct run to allow adequate mixing of sorbent with the flue gas ahead of the particulate collection device, a situation that is especially common for older units equipped with small ESPs.

Retrofit controls on existing plants and controls for new operations will be highly site-specific and dependent on plant configuration, type of coal burned, and existing control technologies in place. In order to bring these control systems on-line, power plants will have to determine site specific mercury emissions requirements and evaluate: the effect of fuel supply; options for reducing emissions; the feasibility of installing control devices; the capital investment and operating costs; the potential impacts on plant operation and by-product management, and, finally, install and operate the equipment. Installation, which can take up to three years, will be constrained by the need to coordinate outages with load demand, and by the limited availability of boilermaker engineering and labor, given EPA's plans to implement its CAIR proposal within the same timeframe.

EPA assumes that fuel switching is not an option for mercury compliance. Therefore under a sufficiently stringent MACT limit, emission reductions will be required from all units using all coal types. Absent fuel switching as an option, compliance will require the addition of mercury-specific technology to be retrofit to the majority of coal-fired utility boilers (ostensibly the 94% of units that fall below the average of the top 12% in emissions) within a period of four years. While this requirement may be lessened somewhat under a cap-and-trade program, it is unlikely that most owners can afford to gamble that sufficient emission allowances will be available to avoid the need to install emission control technology.

This proposed pace of introduction of mercury emission control technology to utility boilers is unprecedented. For comparison, the graph below shows the pace of introduction of flue gas desulfurization (FGD) technology to the U. S. boiler population from first introduction of the technology through the year 2000.

Since the first scrubbers were installed in the early 1970s, about 100GW of scrubber capacity has been build in the last 30 years. Notably, the cumulative total equates to installations on new or existing facilities representing only about 1/3 of the total boiler population. The concept inherent in the current regulatory proposal that essentially all of the 300GW boiler population would be able to install as-yet unproven technology in the span of four years or risk the penalties of non-compliance is highly unrealistic.



Source: U.S. Department of Energy, Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/epav2/html_tables/epav2t30p8.html.

<u>Impacts</u>

In conclusion, NMA believes that neither co-benefit nor mercury-specific control technology is commercially available for coal-fired utility boilers at a predictable level of performance. Although some mercury will be reduced by co-benefit technology, and promising mercury-specific technology is under development, it is premature to set a MACT floor, NSPS standard or emission allowance allocations because of the lack of reliable scientific data on mercury emissions and the performance of control technology. It is unreasonable and arbitrary to base an emissions standard on the hypothetical performance of unproven technology. This is consistent with the NMA recommendation that emissions measurements be conducted on all affected units between 2008 and 2012, that EPA set an interim cap, under a national cap-and-trade program in 2012 for implementation in 2015, and set a final cap of 15 tons for implementation in 2018. This timeline will allow for an adequate understanding of the performance of co-benefit technology before setting emission allocations and for the development through commercial availability of mercury-specific control technology that will be necessary to achieve the 2015 and 2018 caps.

II) NMA's support for, and further clarification of, the comments submitted by the Utility Air Regulatory Group's (UARG), of which NMA is a member

NMA is supportive of the comments being filed by UARG in this rulemaking. There are, however, key differences in our positions, as outlined below:

a) Neither NMA nor UARG supports a MACT approach to the implementation of mercury reductions. If, however, EPA chooses to promulgate a MACT standard, NMA believes that EPA should correct for the deficiencies in the quality and accuracy of EPA's ICR Part III data set before fuel specific emission levels are set. (Our concerns with this data set and EPA methodology for determining MACT floor values are outlined in great detail in our May 14, 2004 comments, and associated attachments.) The ICR III data are not appropriate for the determination of any regulatory standard.

UARG, in its comments, indicates that if EPA implements a MACT standard, then it would endorse the MACT floor limits that it offered during the EPA utility MACT working group meetings. NMA does not support these floor values. As noted above, more data and analysis are needed before these values can be determined.

b) Consistent with UARG's position, NMA proposes that a phased, national cap and trade program (under section 112 of the CAA) be implemented to reduce power plant mercury emissions. We favor a phased approach because it is not possible to predict with adequate confidence the co-benefit reductions that will be achieved through the industry's actions to meet CAIR requirements. In addition, we believe a phased approach will allow for the time that is required for the commercialization of mercury-specific control technologies that will be needed for future reductions. However, a key distinction between our proposed alternatives is that we do not believe that EPA has data that are sufficient to support setting an interim (2015) cap, or emissions allocation factors at this time. As noted above, EPA should determine emissions allocation factors by coal type and set an interim cap in 2012; this interim cap should become effective in 2015. The cap and associated factors should be based on a co-benefits analysis of the monitoring data collected in the 2008-2012 period, and an assessment of commercial availability and performance characteristics of mercury control technologies for different coal types. The analysis performed during this period will allow for the implementation of an interim cap that is achievable (and thus does not promote fuel switching – to natural gas, for example), and avoid emissions allocations among coal ranks that would place certain coal ranks at a market disadvantage.

NMA appreciates the opportunity to provide comments on this proceeding, and trusts that these comments will be of assistance to EPA's regulatory decision.

Sincerely,

A. Todd Johnston
Director of Air Quality