

**UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY**

COMMENTS OF THE UTILITY AIR REGULATORY GROUP

on the

**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
(69 Fed. Reg. 4652 (January 30, 2004))**

and

**SUPPLEMENTAL NOTICE FOR THE 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
(69 Fed. Reg. 12398 (March 16, 2004))**

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ATTACHMENTS

- Attachment 1: UARG Members Joining the Comments.
- Attachment 2: EPRI. Comments on the October 2000 External Review Draft RfD for Methylmercury (November 28, 2000).
- Attachment 3: WHO. Joint FAO/WHO Expert Committee on Food Additives Meeting Summary and Conclusions (June 19, 2003).
- Attachment 4: E. Edgerton. Comments on Mercury Speciation in Coal-Fired Power Plant Plumes (June 8, 2004).
- Attachment 5: C. Whipple. The Sensitivity of Fish Advisories to Changes in the Reference Dose for Mercury (December 30, 1999).
- Attachment 6: RMB Consulting & Research, Inc., Technical Review Comments (June 25, 2004).
- Attachment 7: L. Smith. Subcategorization for Establishing Standards of Performance for Mercury for New and Existing Electric Utility Steam Generating Units (March 2, 2004).
- Attachment 8: J.E. Cichanowicz. Assumptions Adopted By EPA Proposal Regarding the Feasibility of Mercury Controls for MACT Application (June 28, 2004).
- Attachment 9: L. Smith. Input and Output-Based Mercury Limits (April 19, 2004).
- Attachment 10: J.E. Cichanowicz, M. Hein, J. Marchetti. Utility Industry Response to the IAQR Mandates: Estimates of Technology Retrofit and Schedule (March 30, 2004).
- Attachment 11: UARG. Comments on the Proposed Ruled to Reduce Interstate Transport of Fine Particulate Matter and Ozone (IAQR) (March 30, 2004).
- Attachment 12: L. Smith. Potential Combustion Modifications to Capture Mercury Emissions (April 26, 2004).

Comments of the Utility Air Regulatory Group

The Utility Air Regulatory Group (“UARG”)¹ offers the following comments on the U.S. Environmental Protection Agency’s (“EPA” or “Agency”) “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”² and “Supplemental Notice for the 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.”³ In general, EPA’s proposal recognizes the difficulties in controlling mercury emissions from coal-fired units. UARG commends EPA for requesting comment on alternative means of controlling mercury emissions from coal-fired electric utility steam generating units and for including a cap-and-trade option. UARG has a number of specific comments and concerns about EPA’s proposal. These are discussed in detail below and in the attached technical reports.

¹ UARG is a voluntary, nonprofit association of electric generating companies and organizations and four national trade associations (the Edison Electric Institute, the National Rural Electric Cooperative Association, the American Public Power Association, and the National Mining Association). UARG’s purpose is to participate collectively on behalf of its members in EPA’s rulemakings and other Clean Air Act proceedings that affect the interests of electric generators and in litigation arising from those proceedings. A list of UARG members joining in these comments is Attachment 1 to these comments.

² 69 Fed. Reg. 4652-752 (Jan. 30, 2004).

³ 69 Fed. Reg. 12398-472 (Mar. 16, 2004).

Summary of Comments

EPA's rulemaking proposal represents the culmination of thirty years of sampling and analysis of hazardous air pollutant emissions from fossil-fuel-fired electric utility steam generating units to determine whether those emissions pose significant enough risks to public health to warrant regulation. EPA has taken so long to propose any regulations because the risks posed by hazardous air pollutant emissions from fossil-fuel-fired plants are vanishingly small. Only trace amounts of hazardous pollutants are found in fossil fuels and existing control equipment that power plants have installed to comply with the other requirements of the Clean Air Act ("CAA") capture significant amounts of those hazardous pollutants.

In its December 2000 regulatory decision, EPA proposed to control the emissions of two hazardous air pollutants -- mercury from coal-fired units and nickel from oil-fired units. For all other hazardous pollutant emissions, EPA found that the existing evidence does not demonstrate that public health concerns exist. UARG agrees with EPA's conclusions regarding hazardous air pollutants other than mercury and nickel. As for mercury and nickel, UARG believes that EPA's December 2000 decision is legally and factually deficient. EPA's listing decision construes § 112(n)(1)(A) far too narrowly and unduly constrains EPA's regulatory options. EPA has also failed to develop an adequate factual record to conclude that mercury emissions from coal-fired power plants and nickel emissions from oil-fired units are of sufficient public health concern to warrant regulation.

The case for regulating mercury emissions is far different than the unsupported claims and hyperbole that have appeared in many commenters' remarks, newspaper articles, and advertisements. Those claims are aimed more at frightening a largely uninformed public than ensuring sound science underlies EPA's regulatory decision. In fact, there is no evidence in the rulemaking record to show that anyone in the United States has suffered adverse health problems

as a result of mercury emissions from coal-fired power plants. The National Health and Nutrition Examination Survey (“NHANES”) data, often cited to show the need to regulate mercury, reveal that the women having the highest measured mercury exposures had exposures only about one-half the level at which any adverse health effect was first seen in epidemiological tests.

EPA’s decision to regulate mercury emissions from coal-fired power plants rests largely on general concerns about mercury levels in the environment rather than on specific concerns about mercury emissions from coal-fired power plants. EPA readily admits that it cannot quantify the linkage between mercury levels in humans and mercury emissions from coal-fired power plants. Instead, the Agency has cited the number of states having mercury fish advisories and the number of women of child bearing who are predicted to have exposures greater than EPA’s reference dose for mercury as key reasons for its decision to regulate. Those observations are insufficient to support a conclusion that regulation is “appropriate and necessary” under § 112(n)(1)(A). EPA’s factual findings are inextricably tied to its reference dose for methylmercury. That reference dose is the product of a variety of questionable, highly conservative assumptions that produce a value that is lower than any comparable level developed by other governmental entities. This may or may not have been a problem had EPA considered all of the conservatisms embedded in its reference dose when it made its regulatory decision. However, EPA appears to have ignored those underlying assumptions and improperly used its reference dose as a bright-line test for deciding if public health concerns exist. EPA needs to revisit the legal and factual bases for its December 2000 listing decision.

EPA’s December 2000 listing decision and its subsequent rulemaking proposal provide little factual support for the Agency’s decision to regulate nickel emissions from oil-fired units.

The only evidence cited by EPA is from its Utility Study to Congress which included highly conservative, screening-level risk assessments of oil-fired plants. Those conservative assessments predicted that less than 10% of the oil-fired units had risks greater than one-in-one million. EPA did not update those analyses either for its listing decision or its rulemaking notice even though more recent information was available showing that the forms of nickel emitted by oil-fired units are less toxic than EPA assumed in its risk analyses and that many of the highest risk oil-fired plants have either ceased burning oil or have been retired. EPA should rescind its decision to regulate nickel emissions from oil-fired units.

EPA's proposal requests comments on two very different approaches to controlling mercury emissions from coal-fired power plants -- a command-and-control approach that would impose MACT limits on every plant and a cap-and-trade program that would allow utilities to achieve mercury reductions in the most economically efficient way. Any regulatory program to reduce mercury emissions from coal-fired power plants must begin by recognizing that mercury health concerns, to the extent there are concerns, are global in nature. Over 75% of the mercury that deposits in the United States comes from sources outside the United States. Mercury emissions from U.S. coal-fired power plants constitute only about 1% of the global emissions of mercury. Much of the mercury emitted by coal-fired power plants is in the elemental form which enters the global pool. EPRI modeling work predicts that reducing mercury emissions from coal-fired power plants from 45 tons per year to 15 tons per year will only reduce mercury deposition in the United States by 11.5 tons per year (or 6.9% of total annual mercury deposition in the United States). Given the global nature of mercury, it makes little environmental or economic sense to impose command-and-control requirements on every coal-fired power plant.

Rather, a cap-and-trade program similar to the one proposed by EPA is the best way to produce the largest mercury reductions in the most efficient manner.

UARG believes that if EPA proceeds to regulate mercury emissions from coal-fired power plants, it should do so using a nationwide cap-and-trade program promulgated under § 112(n)(1)(A) of the CAA. UARG recommends that a mercury cap-and-trade program be implemented in three phases. In Phase 1, there should not be a numeric cap on mercury emissions. Instead, mercury emission reductions would be those resulting from coal-fired power plants' installing new control equipment to comply with the requirements of EPA's proposed Clean Air Interstate Rule ("CAIR"), assuming that EPA promulgates that rule.⁴ Mercury trading would not occur during Phase 1. Mercury allowances would not be issued and banking of mercury allowances would not occur. Coal-fired units would install and certify mercury monitors in 2008 and begin to monitor mercury emissions in 2009. The main reason a numeric cap should not be established in Phase 1 is because there is no way to predict the level of mercury reductions that will be a result from utilities' efforts to meet the CAIR requirements. Not setting a numeric limit avoids excess banking of allowances if the cap was set too high, and conversely, compliance problems if the cap is set below the level of mercury reductions actually achieved from complying with the CAIR. Phase 2 would begin in 2015 with a cap of 24 tons of mercury emissions per year. In Phase 2, mercury allowances would be allocated and mercury trading could occur. Allowances should be allocated on the basis of heat input. UARG suggests

⁴ The Clean Air Interstate Rule was previously known as the Interstate Air Quality Rule. EPA has proposed Phase 1 of CAIR to begin in 2010. UARG has submitted comments in EPA's CAIR rulemaking that, among other things, argue that EPA's proposed CAIR requirements are, as legal matter, premature under the existing provisions of the Clean Air Act, and that if EPA nevertheless promulgates CAIR, the Phase 1 compliance deadline for sources subject to CAIR should be no earlier than 2012. UARG stands by those comments. UARG also will be submitting comments on EPA's supplemental notice of proposed rulemaking CAIR.

heat input multipliers of 1.0 for bituminous units, 1.5 for subbituminous units and 3.0 for lignite units. Phase 3 would begin in 2018 with a cap of 15 tons per year. The main problems with EPA's cap-and-trade proposal center on the overly stringent limits on new units and the emissions monitoring and compliance requirements. These issues are addressed in Section VI below.

While UARG does not believe that EPA should impose mercury Maximum Achievable Control Technology ("MACT") limits on coal-fired power plants, EPA's MACT proposal does a good job of addressing the important issues identified during EPA's utility MACT working group meetings. EPA's decision to create subcategories based on the rank of coal a unit burns reflects the inherent differences in the species of mercury created from burning different coals. EPA's proposal acknowledges the limited nature of the 1999 Information Collection Request ("ICR") stack testing data and accounts for the large variability in the mercury emissions at the best performing units by adjusting the MACT floors and by specifying a 12-month rolling average for compliance. The proposed MACT rule also provides utilities with needed operational flexibility by allowing compliance to be demonstrated on a facility-wide basis and by permitting utilities to choose between two monitoring methods to demonstrate compliance. The main problems with EPA's MACT proposal are: (1) the proposed MACT limits for new units are set far too low because they fail to reflect all sources of mercury variability, (2) the proposal fails to include a percentage reduction compliance option, (3) the three-year compliance period is too short for all coal-fired units to come into compliance with EPA's proposed MACT limits, and (4) EPA's emission monitoring and compliance provisions require substantial revision.

These issues are discussed in much greater detail in the following comments. Section I addresses the legal and factual adequacy of EPA's December 2000 regulatory determination and

listing decision. Section II discusses EPA's decision not to regulate HAPs other than mercury and nickel. Section III discusses EPA's regulatory options under § 112(n)(1)(A) and the need to integrate the timing of any hazardous air pollutant limits with EPA's proposed CAIR. Section IV addresses EPA's proposed MACT rule, including the significant concerns UARG has with EPA's proposed standards for new sources, with the need for a percent reduction alternative, with the time provided to comply with the proposed MACT rule, and with many emissions monitoring and compliance provisions. Section V addresses EPA's MACT proposal for oil-fired units. Section VI presents UARG's alternative cap-and-trade approach. The section also discusses UARG's recommendations for implementing any cap-and-trade program, including UARG's concerns with EPA's monitoring and compliance provisions. Finally, Section VII addresses a number of other issues and certain EPA requests for comment.

Specific Comments

I. EPA's December 2000 Regulatory Determination and Listing Decision Are Neither Legally Nor Factually Justified

UARG believes that EPA's December 2000 decision is legally and factually deficient. EPA's December 2000 listing decision was issued without any public input. As a result, the legal and factual bases for that decision were never exposed to public questioning nor was EPA challenged to explain and defend its action. EPA's actions and public statements preceding its December 2000 decision did not foreshadow the decision to list coal- and oil-fired electric utility steam generating units under § 112(c). Indeed, EPA's Utility Study to Congress found only that mercury was the hazardous pollutant of "greatest concern."⁵ It did not include a finding that

⁵ EPA, "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units -- Final Report to Congress," EPA-453/R-98-004a (Feb. 1998)("Utility Study") (Docket No. A-92-55-I-A-90).

mercury emissions from coal-fired power plants posed a public health concern. The report expressly stated that it did not include a regulatory determination and that EPA was delaying a regulatory determination to some undefined date in the future.⁶

Following EPA's issuance of its December 2000 listing decision, UARG sought immediate review of that decision in the U.S. Court of Appeals for the District of Columbia Circuit.⁷ EPA resisted UARG's petition by arguing that the challenge was premature. EPA explained to the court that "[w]hile we do not presently see any viable alternative construction of the statute, we note that the entire predicate for EPA's finding determination and listing decision (both legal and factual) is susceptible to further comment and administrative review in the forthcoming MACT standard rulemaking."⁸ Based on that assertion, the court dismissed UARG's appeal as premature. As a result, UARG now presents its legal and factual concerns with EPA's December 2000 listing decision.

A. Section 112 of the CAA Does Not Require EPA to Set MACT Limits Under § 112(d) If the Agency Finds That Regulation of Certain Hazardous Pollutants Is "Appropriate and Necessary" Under § 112(n)(1)(A)

EPA Administrator Browner found in her December 2000 decision that mercury emissions from coal-fired electric utility steam generating units posed a public health concern and that regulation of these sources was "appropriate and necessary."⁹ Despite earlier statements

⁶ *Id.* at ES-1.

⁷ On February 20, 2001, UARG also filed a petition for administrative reconsideration of EPA's listing decision. EPA has never acted on that petition for reconsideration.

⁸ EPA's Reply in Support of Motion to Dismiss, *UARG v. EPA*, No. 01-1074 at 4 (D.C. Cir. May 17, 2001).

⁹ 65 Fed. Reg. 79825, 79830 (December 20, 2000). Administrator Browner also found that mercury emissions posed an environmental concern. As EPA has correctly recognized in its rulemaking proposal, 69 Fed. Reg. at 4683, this part of Administrator Browner's decision was
(continued...)

by EPA about its regulatory flexibility under § 112(n)(1)(A),¹⁰ Administrator Browner concluded that the only option EPA had for regulation, once there was a finding that regulation was necessary and appropriate, was to list electric utilities under § 112(c) and to proceed to develop MACT standards under § 112(d).¹¹

The decision to proceed under the MACT provisions of § 112(d) construes § 112(n)(1)(A) far too narrowly and unduly constrains EPA's present regulatory options. The MACT provisions require EPA to impose command and control limits on every unit in a source category based solely on the level of control achieved by the best performing units. As a result, a MACT approach is blind to the health consequences of the emissions it seeks to limit and is cost inefficient.

Section 112(n)(1)(A) provides EPA broad discretion to address any specific public health risks EPA identifies as a result of its Utility Study to Congress. Section 112(n)(1)(A) requires EPA to regulate “*under this section*” if regulation is found to be “appropriate and necessary.” Section 112(n)(1)(A) does not specify that regulation must proceed under § 112(d) or, for that matter, under any other provision of § 112. Instead, the section requires EPA to “develop and describe” alternative control strategies for emissions which may warrant regulation. The

legally incorrect because § 112(n)(1)(A) commands that the Administrator look only at the possible hazards to public health in deciding whether regulation is “appropriate and necessary.”

¹⁰ See Brief of Respondents, *EPA et al., NRDC v. EPA*, No. 92-1415, at 25-26 (D.C. Cir. Sept. 14, 1993) (emphasizing EPA's discretion to determine whether regulation is “appropriate and necessary” based on the results of the study required under § 112(n)(1)); see also *Determination of Adequacy of Section 112 Authorities and Determination of Need for Additional Standards*, 63 Fed. Reg. 14090, 14105 (Mar. 24, 1998) (emphasizing that regulation of HAP emissions can be by other means than imposition of MACT standards based on EPA's “necessary and appropriate” determination).

¹¹ See 65 Fed. Reg. at 79830; see also EPA Motion to Dismiss, *UARG v. EPA*, No. 01-1074, at 10 (D.C. Cir. Apr. 9, 2001).

development of alternative control strategies would be a pointless paperwork exercise if EPA's only option was to regulate under the MACT provisions of § 112(d). This is because the MACT provisions operate in a mechanical way that exclude most control options. Surely when Congress instructed EPA to identify alternative control strategies, it also provided EPA authority to implement whatever control strategy EPA found most appropriate to address any identified health concerns.

Section 112 and its legislative history support a broad reading of EPA's options under § 112(n)(1)(A). In 1990, Congress substantially amended § 112 of the Clean Air Act, which governs the regulation of hazardous air pollutant emissions. Before the 1990 CAA amendments, § 112 required EPA to list hazardous air pollutants and then to regulate sources of those emissions so as to protect public health with an ample margin of safety.¹² The 1990 CAA amendments enacted a radically different regulatory approach under § 112 for virtually all emission sources. Congress listed 189 substances as "hazardous air pollutants"¹³ and instructed EPA in § 112(c) to list all categories of "major" and "area sources" of hazardous air pollutant emissions. The criteria for listing source categories under § 112(c) are simple and perfunctory: "the Administrator shall establish . . . a list of all categories and subcategories of major sources and area sources . . . of the air pollutants listed pursuant to the subsection (b)."

Once a source category is listed under § 112(c), EPA is required to set emission standards under § 112(d) based on the maximum degree of reduction in emissions achieved by the best

¹² See generally *NRDC v. EPA*, 824 F.2d 1146 (D.C. Cir. 1987).

¹³ CAA § 112(b), 42 U.S.C. § 7412(b).

controlled similar sources.¹⁴ Only after EPA has established these technology-based standards can it consider public health effects and other factors to determine if more stringent limits should be imposed.¹⁵

Congress treated electric utility steam generating units differently than all other source categories under § 112.¹⁶ Rather than automatically subjecting these units to the § 112(c)/§ 112(d) regulatory scheme, Congress enacted § 112(n)(1)(A) to govern any § 112 regulation of these units. Section 112(n)(1)(A) requires EPA to study any hazards to public health reasonably anticipated to occur as a result of hazardous air pollutant emissions from electric utility steam generating units, after considering the impact of the other provisions of the CAA on this source category. As part of that evaluation, Congress directed the Agency to “develop and describe” alternative control strategies for emissions which may warrant regulation. Finally, Congress directed EPA to determine whether regulation of these units is “*appropriate and necessary after considering the results of the [public health hazards] study*” (emphasis supplied).¹⁷

¹⁴ *Id.* § 112(d) 42 U.S.C. § 7412(d). These standards are often called “maximum achievable control technology” or “MACT” standards.

¹⁵ *Id.* § 112(d)(2), (3), (4), 42 U.S.C. § 7412(d)(2), (3), (4).

¹⁶ Congress recognized that electric utility steam generating units were targeted for regulation under a number of provisions of the 1990 CAA Amendments, including the “acid rain” provisions of Title IV (*Id.* §§ 401-416, 42 U.S.C. §§ 7651a-7651o).

¹⁷ Section 112(n)(1)(A) states:

The Administrator shall perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed under subsection (b) of this section after imposition of the requirements of this Act. The Administrator shall report the results of this study to the Congress within 3 years after November 15, 1990. The Administrator shall develop and describe in the Administrator’s report to Congress alternative control strategies for emissions which may

(continued...)

The legislative history of § 112(n)(1)(A) sheds further light on Congress' unique approach to regulation of electric utility steam generating units under § 112. S. 1630, which passed the Senate on April 3, 1990, would have required EPA to list electric utility steam generating units under § 112(c) and to regulate them under the MACT provisions § 112(d).¹⁸ When the House passed a modified version of S. 1630 on May 23, 1990, it substantially changed the § 112 provisions related to electric utility steam generating units. The House-passed provision was virtually identical to the current § 112(n)(1)(A),¹⁹ and was ultimately adopted by the conference committee and became law.²⁰

Representative Oxley, a sponsor of the House provision and a member of the conference committee, explained the intent of § 112(n)(1)(A):

Pursuant to section 112(n), the Administrator may regulate fossil fuel fired electric utility steam generating units *only* if the studies described in section 112(n) clearly establish that emissions of any pollutant, or aggregate of pollutants, from such units cause a significant risk of serious adverse effects to the public health. Thus, . . . he may regulate only those units *that he determines* – after taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary

warrant regulation under this section. The Administrator shall regulate electric utility steam generating units under this section, if the Administrator finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph.

¹⁸ See S. 1630, § 301 (passed by the Senate on April 3, 1990), reprinted in “*A Legislative History of the Clean Air Act Amendments of 1990*,” Vol. 3, at 4407 (1993) (“1990 Legis. Hist.”). The Senate would have required EPA to conduct a study of the remaining risk of hazardous air pollutants after it had imposed MACT standards.

¹⁹ *Id.*, Vol. 2, at 2148-49.

²⁰ *Id.*, Vol. 1, at 572-73.

emission reductions -- *have been demonstrated to cause a significant threat of serious adverse effects on the public health.*²¹

Thus, Congress directed EPA to make a regulatory determination regarding fossil-fuel-fired generating units, based on consideration of any adverse public health effects identified in the study mandated by the first sentence of § 112(n)(1)(A). Congress did *not* dictate in § 112(n)(1)(A) that EPA must regulate electric utility steam generating units under § 112. EPA first had to conclude that regulation was “appropriate and necessary.” Even if EPA concluded that regulation was appropriate and necessary, Congress did *not* require EPA to regulate “under subsection (d) of this section” – the language used in CAA § 112(c)(5), 42 U.S.C. § 7412(c)(5), for most source categories – or, for that matter, any other specific subsection of § 112.

Thus, EPA’s December 2000 listing decision rests on an incorrect reading of § 112(n)(1)(A). It unnecessarily constrains EPA’s ability to develop the most efficient means of controlling mercury emissions from electric utility steam generating units. EPA must reconsider and reverse its listing decision during this rulemaking proceeding.

B. EPA’s Conclusion That Regulation of Mercury Emissions from Coal-Fired Power Plants Is Appropriate and Necessary Is Not Supported by the Factual Record

EPA’s December 2000 decision does not contain a concise explanation of the factual bases for EPA’s conclusion that mercury emissions from coal-fired power plants pose a risk to public health that warrants regulation. At various places in the regulatory decision, EPA discusses (1) a “plausible link” between mercury emissions from coal-fired power plants and mercury levels in fish (although the Agency admits that it cannot quantify the linkage), (2) the existence of fish advisories for mercury in waterbodies in 40 states, (3) that mercury is a

²¹ 136 Cong. Rec. H12934 (daily ed. Oct. 26, 1990), *reprinted in* 1990 Legis. Hist., Vol. 1, at 1416-17 (emphasis supplied).

persistent, bioaccumulative toxic (“PBT”) chemical, and (4) that electric utility steam generating units are the largest source of mercury emissions in the United States. EPA’s rulemaking proposal repeats many of these same assertions and adds that the recent NHANES study shows that 8% of women of child bearing age have mercury levels in their blood above EPA’s reference dose (“RfD”) for mercury. These assertions, taken individually or collectively, are insufficient to establish public health concerns that warrant a conclusion that regulation is “appropriate and necessary.”

1. EPA’s Reference Dose for Methylmercury Is Highly Conservative

Any determination about the public health risks posed by mercury emissions from coal-fired power plants must begin with an examination of EPA’s RfD for methylmercury and how that RfD was derived. The appropriate RfD for methylmercury has been the subject of considerable disagreement among federal and international agencies for many years and remains controversial today.

EPA originally proposed its reference concentration (“RfC”)/RfD methodology for the primary purpose of identifying “residual risk” for non-carcinogenic threshold pollutants under CAA § 112(f).²² As a result, the RfC/RfD methodology was developed as a screening tool for deciding when risks clearly do not exist; the methodology was never designed to identify the existence of actual health risks or to quantify their magnitude. EPA itself has recognized that “[e]xceeding the RfC does not necessarily indicate that a public health risk will occur.”²³ In fact,

²² 55 Fed. Reg. 39321 (Sept. 26, 1990).

²³ 59 Fed. Reg. 42250 (Aug. 17, 1994). EPA has also noted that “[b]y definition, RfC analyses do not yield a precise concentration that defines a demarcation between safety and hazard . . . the RfC is a protective level, not a predictive one.” *Id.* EPA added “at present, it is impossible to state whether projected exposures above the RfC would result in an adverse health effect for either an individual or the general population.” *Id.*

in its 1991 early reduction rulemaking under § 112(i)(5) EPA stated that “to estimate a level [of exposure] at which public health risks could be potentially significant . . . it [is] appropriate to consider exposure levels *one order of magnitude higher than the reference concentration or dose.*”²⁴

EPA misused its RfD for methylmercury in the December 2000 listing decision. EPA used the RfD as if it were an absolute threshold for health risk. By so doing, EPA avoided having to demonstrate some identifiable health risk to some segment of the population at some defined level of predicted exposure. EPA’s methylmercury RfD is an important factor in two key “factual findings” EPA used to justify its listing decision: (1) the existence of fish advisories in many States and (2) the number of women of child bearing age who are predicted to have methylmercury exposures above the reference dose. As is discussed in more detail below, both findings are highly dependant on where one sets the RfD.

EPA’s RfD for methylmercury rests on a series of highly conservative assumptions. As a result, EPA’s RfD is lower than any comparable value developed by any other federal or international agency. The public was largely excluded from EPA’s development of the methylmercury RfD²⁵ and was precluded from challenging that RfD in court. This closed

²⁴ 56 Fed. Reg. 27363 (June 13, 1991) (emphasis supplied).

²⁵ EPA states that its RfDs are developed based on a “consensus” of EPA scientists. If one examines EPA’s description of its RfD process, one finds that EPA does not use “consensus” to mean unanimity. Instead, EPA says that “consensus may be reached when there is general agreement among a strong majority of the Offices and regions that have participated.” See EPA’s Integrated Risk Information System (“IRIS”) Website, “U.S. EPA’s Process for IRIS Assessment Development and Review (Apr. 2004),” available at <http://www.epa.gov/iris/process.htm>.

In the case of methylmercury, the public was given an opportunity to submit written comments on EPA’s proposed RfD. That opportunity was largely symbolic as EPA basically
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process allowed EPA to set a highly conservative RfD and then later use that RfD as a bright-line test for concluding that public health risks exist. EPA cannot hide behind its RfD and avoid establishing the existence of real public health concerns.

a. EPA's RfD Should Not Have Been Developed Solely on the Basis of the Faroe Islands Study

EPA's RfD is derived solely from the results of a study of young children in the Faroe Islands. In so doing, EPA ignored an equally detailed study of young children performed in the Seychelle Islands.²⁶ EPA chose to use the Faroes study because it revealed adverse developmental effects as a result of methylmercury exposure, while the Seychelles work did not reveal similar effects.²⁷

EPA's sole use of the Faroe Islands study is suspect for several reasons. First, the raw data from the Faroe Islands work have never been made available for independent analysis and scrutiny. By contrast, the raw data from the Seychelle Islands have been made available to other

ignored those comments. A review of EPA's response to comments shows that the Agency dismissed public comments with little more reasoning than "we are in charge of setting the RfD and here is where we have decided to set it."

²⁶ See IRIS Database, Methylmercury, § I.A.2 (2001). EPA's choice of the Faroe Islands work may, in part, have resulted from recommendations in the 2000 report of the National Research Council (NRC), entitled *Toxicological Effects of Methylmercury*. That report found that there were no serious flaws in the methylmercury studies conducted in the Seychelle and Faroe Islands. The panel recommended the use of the Faroe study in deriving a reference dose because it resulted in the finding of a positive relationship between methylmercury exposure and poor neurodevelopmental outcomes while the Seychelles study did not reveal a similar relationship. *Id.* at 4-5. The problem with EPA's reliance on the NRC report is that the panel's conclusion is, at base, a policy judgment and not a conclusion about the science of methylmercury. In making this recommendation, the NRC strayed beyond its initial charge. EPA needs to make its own policy judgments in setting RfDs so that all of its RfDs are consistent.

²⁷ EPA's approach is different than ones used by the Agency for Toxic Substances and Disease Registry ("ATSDR") and the World Health Organization ("WHO"). Both ATSDR and WHO used the Seychelles results as part of their analyses.

independent scientists. The refusal of the Faroe Islands researchers to release their raw data to allow independent statistical analyses should have caused EPA to question the value and use of those results under its own data quality guidelines.²⁸

Second, as the Electric Power Research Institute's ("EPRI") comments on EPA's proposed RfD for methylmercury pointed out,²⁹ the polychlorinated biphenyl ("PCB") exposures of pregnant women in the Faroe Islands are among the highest ever measured in humans. PCBs are important because the confounding effects of PCBs can lead to a false positive association between methylmercury exposure and childhood development. The original study of methylmercury in the Faroes measured PCBs in cord tissue.³⁰ Yet the researchers only measured three PCB congeners and then for only one half of the study population. EPA discounts the possible confounding effect of PCBs by relying on a statistical analysis performed by the Faroe Island researchers at the request of the NRC.³¹ Their analysis showed no confounding effects from PCBs. Yet, EPA and the NRC have both failed to ask the fundamental question: why did the Faroes study fail to observe any significant effects from PCBs when PCB exposures were at levels twice as high as the lowest observed effect level ("LOAEL") for those compounds?

²⁸ See "Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information Disseminated by the Environmental Protection Agency," EPA/260R-02-008 (Dec. 2002).

²⁹ Comments of the Electric Power Research Institute Regarding Reference Dose for Methylmercury, at 7-8 (Nov. 28, 2000) (Attachment 2).

³⁰ Sampling PCBs in cord blood is an unconventional method of unknown reliability for assessing exposure to PCBs.

³¹ See IRIS Database, Methylmercury, § I.A.2 (2002). Again, the Faroe Island researchers did not make the raw data from their work available so that EPA or independent scientists could reproduce their statistical analyses.

Third, questions exist about whether the Boston Naming Test -- the test cited by the Faroe Island researchers as establishing adverse neurodevelopmental effects from methylmercury exposures -- is capable of detecting the subtle changes in response the Faroe Island researchers claim to have detected. Comments submitted by EPRI in this docket describe the limitations of the Boston Naming Test.³² EPRI concludes that the risk of adverse neurodevelopmental effects for children exposed to methylmercury at or above EPA's RfD is not distinguishable from background occurrences if one uses the Boston Naming Test. If EPA had used the Seychelles results either alone or by averaging them with the results from the Faroes, a higher RfD would have been derived.

b. EPA Did Not Follow Its Historic Approach When It Derived a Benchmark Dose from the Faroe Islands Data

The first step in deriving an RfD is normally to determine a "no observed effect level" ("NOAEL"). As the science for setting RfDs has advanced, EPA has begun to use a benchmark dose ("BMD") as a substitute for the NOAEL.³³ Recognizing the need for consistency between RfDs based on NOAEL and later ones based on BMDs, EPA has noted that research demonstrates that the 10% risk level of benchmark dose roughly correlates with the NOAEL.³⁴ However, for its most recent revision to the methylmercury RfD, EPA chose to depart from this historic approach and instead use a 5% risk level for the benchmark dose. Both peer reviewers and public commenters questioned EPA's use of a more conservative BMD approach. EPA's

³² See EPRI "Comments on EPA Proposed Emission Standards/Proposed Standards of Performance, Electric Utility Steam Generating Units: Mercury Emissions," at 23-27 (June 16, 2004).

³³ UARG commends EPA for using this latest statistical approach in setting the methylmercury RfD.

³⁴ See EPA's 1995 IRIS RfD for methylmercury.

response to those comments was that “EPA has no policy on the choice of BMD, which is chosen on a case-specific basis.”³⁵ Thus, EPA’s stated purpose of having consistency among its RfDs was not followed in the case of methylmercury. The net result of EPA’s choice of a 5% risk level is a BMD that is six times more stringent than the traditional 10% risk level BMD or NOAEL approach.³⁶

c. The Uncertainty Factor Used by EPA to Set the Methylmercury RfD Is Too High and Without Scientific Justification

EPA’s RfD for methylmercury also applies an uncertainty factor of 10 to the benchmark dose. This uncertainty factor is comprised of two factors of three: one to account for pharmacokinetic variability and the second to account for toxicodynamic variability and uncertainty.³⁷ The further conservatism imbedded in EPA’s uncertainty factor becomes apparent when one examines the history of EPA’s reference doses for methylmercury and EPA’s justification for the two adjustment factors of three.

The Seychelles and Faroes studies were designed to study the effects of chronic methylmercury exposures on the most sensitive individuals. These studies provide far better information on chronic low level exposures -- which are representative of exposures in the U.S.³⁸ -- than the acute, high-dose poisoning incidents in Iraq and Japan that EPA used to set RfDs for

³⁵ EPA’s Response to Comments of the Peer Review Panel and Public Comments on Methylmercury, at 8. This comment again points out the shifting nature of EPA’s RfD process and why the Agency cannot rely on RfDs as bright-line tests for regulatory decisions.

³⁶ See Comments of the Electric Power Research Institute Regarding Reference Dose for Methylmercury, at 3-4 (Attachment 2).

³⁷ See IRIS Database, Methylmercury, § I.A.2, Choice of Uncertainty Factor (2001).

³⁸ The study populations in the Seychelles and Faroes were chosen because of their relatively high levels of methylmercury exposure. Both populations were exposed to methylmercury levels well in excess of typical U.S. exposures.

methylmercury in 1980 and 1995. Despite these fundamental differences in test subjects, EPA continues to use the same uncertainty factor of 10 that it used when it derived RfDs from the Iraqi and Japanese data. EPA attempts to support its newest uncertainty factor of 10 by introducing several novel theories of uncertainty that are poorly explained and justified.

First, EPA has assigned an unusually high uncertainty factor of three to account for pharmacokinetic variability. Much of the uncertainty EPA attributes to this source of variability results from the model selected by EPA. EPA used a one-compartment model instead of the more sophisticated Psychologically Based Pharmacokinetic Model (“PBPK”) model suggested by the National Research Council (“NRC”) panel. EPA would have eliminated much of the model-based uncertainty by using the PBPK model.³⁹ Indeed, for a PBPK model, an uncertainty factor closer to one would have been more appropriate.⁴⁰

EPA’s RfD documentation fails to explain why an uncertainty factor of three was applied to address toxicodynamic variability and uncertainty when such a factor was considered unnecessary in the EPA’s earlier methylmercury RfDs based on poisoning incidents in Iraq and Japan.⁴¹ Again, one must question whether EPA’s stated purpose of setting RfDs based on

³⁹ See Harvey J. Clewell, *et al.*, “Evaluation of the Uncertainties in an Oral Reference Dose for Methylmercury Due to Interindividual Variability in Pharmacokinetics,” 19 Risk Analysis, at 547-58 (1999).

⁴⁰ See Comments of the Electric Power Research Institute Regarding EPA’s Reference Dose for Methylmercury, at 4-6 (Attachment 2).

⁴¹ EPA and NRC have both noted the existence of studies that indicate a possible linkage between mercury exposure and cardiovascular effects. These studies were limited and their results have been contradicted by other studies. In addition, a question exists whether the cardiovascular effect, assuming the effect is real, occurs at mercury exposure levels below those used to set EPA’s RfD. So many questions exist about these studies that they should not be used to justify the addition of further uncertainty factors. When WHO released its recent recommendations on methylmercury, it noted that “[t]he Committee determined that the available evidence on the potential cardiotoxicity of methylmercury is not conclusive, but noted
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common principles and assumptions took a backseat to outcome-oriented considerations in setting the methylmercury RfD.

EPA's uncertainty factor of 10 is higher than the uncertainty factors used by the World Health Organization ("WHO") and Agency for Toxic Substances and Disease Registry ("ATSDR"). WHO used an uncertainty factor of 6.4⁴² and ATSDR used an uncertainty factor of 4.5.

d. Conclusion

As the preceding discussion demonstrates, EPA's RfD for methylmercury rests on a series of very conservative assumptions. As a result, the RfD should only be used as a screening tool for deciding when negligible risks exist that can be ignored as a regulatory matter. It should not be used to conclude that anyone exposed at levels above the RfD suffers adverse health effects. EPA appears to have ignored the conservative assumptions in its methylmercury RfD when it issued its December 2000 listing decision. Instead, EPA improperly used the methylmercury RfD as a bright-line test for concluding whether a person is "at risk" from mercury exposures. As a result, EPA's December 2000 listing rests on a flawed basis and must be revisited.

2. EPA's stated bases do not support a conclusion that mercury emissions from coal-fired power plants pose a risk to public health

The factual conclusions offered by EPA to support its 2000 listing decision can be grouped into two basic categories: (1) findings about mercury emissions from coal-fired power

that further studies are needed." Food and Agriculture Organization of the United Nations, World Health Organization, "Joint FAO/WHO Expert Committee on Food Additives Summary and Conclusions," at 20 (2003) ("WHO Study") (Attachment 3).

⁴² *Id.* at 22.

plants and (2) general concerns about the level of mercury in the environment regardless of the source of origin. In the first category, EPA has found (1) that there is a “plausible link” between mercury emissions from coal-fired power plants and methylmercury levels in fish and (2) that coal-fired power plants are the largest source of anthropogenic mercury emissions in the U.S. EPA’s more general concerns focus on the number of fish advisories for methylmercury that exist in the U.S. and estimates of the number of women of child-bearing age who may be exposed to levels of methylmercury that are above EPA’s reference dose. As will be discussed below, these concerns are insufficient to warrant a finding that regulation of coal-fired power plants is “appropriate and necessary.”

a. EPA’s Plausible Link Conclusion

EPA first concluded that there is a “plausible link between anthropogenic releases of mercury from industrial and combustion sources in the United States and methylmercury in fish” in its Mercury Study to Congress.⁴³ In that report, EPA was quick to add that methylmercury concentrations in fish also result from existing background concentrations of mercury and from deposition of mercury from the global pool.⁴⁴ EPA went on to find that “[g]iven the current scientific understanding of the environmental fate and transport of [mercury], it is not possible to quantify how much of the methylmercury in fish consumed by the U.S. population is contributed by U.S. emissions relative to other sources of mercury.”⁴⁵ Furthermore, EPA recognized that it

⁴³ “Mercury Study Report to Congress,” Vol. 1, at O-2 (Dec. 1997) (Docket No. A-92-55-I-A-125-133).

⁴⁴ *Id.*

⁴⁵ *Id.* In subsequent documents EPA has repeated that it cannot quantify the linkage between mercury emissions from coal-fired power plants and methylmercury levels in fish. *See* 65 Fed. Reg. at 79825; 69 Fed. Reg. at 4652.

could not assume that a change in mercury emissions from coal-fired power plants would result in a linear change of methylmercury levels in fish or even over what time those changes would occur.⁴⁶

EPA issued its Utility Study to Congress in February 1998 -- two months after issuing the Mercury Study. The Utility Study did not expand the “plausible link” conclusion. In the Utility Study, EPA deferred making a regulatory decision until “a later date.”⁴⁷

In the December 2000 determination, EPA relied on the “plausible link” conclusion as a lynchpin for its finding that regulation of utility mercury emissions from power plants is “appropriate” and “necessary,” and for listing electric utility generating stations under § 112(c). EPA did not explain why a finding that was insufficient to support a regulatory determination in the Utility Study in 1998 became sufficient two years later.⁴⁸

Reduced to its essence, EPA’s “plausible link” conclusion does little more than state the following series of truisms -- power plants emit mercury; some of that mercury is bound to deposit on the land or in water bodies; some of the mercury in waterbodies can be transformed to methylmercury in the sediments; and some of the methylmercury produced in the sediments enters the food chain where some of it ultimately ends up in humans as a result of their eating fish. EPA’s plausible link conclusion is insufficient to justify regulation. Section 112(n)(1)(A) requires EPA to determine if further regulation of power plants is “appropriate and necessary” to

⁴⁶ Mercury Study, Vol. 1, at O-2 (Dec. 1997)(Docket No. A-92-55, I-A-125-133).

⁴⁷ Utility Study at ES-1.

⁴⁸ EPA simply dismisses the need to resolve the uncertainties that prevented a decision in the Utility Study, explaining that “it is not necessary to quantify the amount of mercury in fish due to electric utility steam generating unit emissions relative to other sources for purposes of this finding.” 65 Fed. Reg. 79827.

protect public health.⁴⁹ EPA's failure to quantify the linkage between mercury emissions from power plants and mercury levels in fish prevents it from concluding that regulation is either appropriate or necessary.⁵⁰ Scientific evidence demonstrates that EPA's plausible link conclusion is a far too simplistic depiction of mercury in the environment. For example, one cannot assume that a given percentage reduction in mercury emissions from coal-fired plants will result in an equivalent reduction in mercury levels in fish. Indeed, detailed modeling studies performed by EPRI have shown that coal-fired power plants are responsible for less than 8% of the mercury deposited in the United States.⁵¹ If ionic emissions from coal-fired power plants were reduced by 10%, mercury deposition in the U.S. would decrease by only 0.75%. If elemental mercury emissions from coal-fired power plants were reduced by 10%, the resultant drop in mercury deposition in the U.S. would be only 0.03%. EPRI's 8% estimate still overstates the mercury deposition resulting from coal-fired power plant emissions because it may not account for all of the atmospheric conversion of ionic mercury to elemental mercury.⁵²

⁴⁹ See H.R. Rep. No. 95-294, at 3, 48-49 (1977) (adopting endangerment as "the standard which the Administrator must meet before promulgating regulations controlling the emissions of any pollutant) (emphasis supplied); *Ethyl Corp. v. EPA*, 541 F.2d 1, 12, 16, 31-32 (the "will endanger" language has been interpreted to require a finding of "significant risk of harm to the public health.").

⁵⁰ A hypothetical link between utility emissions and fish mercury levels does not satisfy EPA's fact finding obligation. Rather, EPA must provide a "more-than-theoretical basis" for a showing that a source exposes the public to a level of a pollutant that is sufficient to cause an "unreasonable risk of injury to health." *Chemical Mfrs. Ass'n v. EPA*, 859 F.2d 977, 988 (D.C. Cir. 1988).

⁵¹ EPRI, "A Framework for Assessing the Cost-Effectiveness of Electric Power Sector Mercury Control Policies," at 2-6 (May 2003) (Docket No. OAR-2002-0056-2588).

⁵² Plume measurements at the Bowen and Pleasant Prairie power plants have revealed that ionic mercury converts to elemental mercury shortly after exiting the stack. See EPRI Comments at 17-19. This chemical reaction may account for the fact that mercury dispersion
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b. The Total Amount of Mercury Emitted by Coal-Fired Power Plants

EPA's statements that coal-fired power plants are the largest source on mercury emissions in the U.S. are also insufficient to warrant a finding that regulation is appropriate and necessary under § 112(n)(1)(A). Simply identifying the amount of mercury that a given source category emits does not answer the key question that EPA must resolve under § 112(n)(1)(A): Do mercury emissions from coal-fired power plants pose a significant risk to human health?

The combustion of coal to produce electricity is one of the largest industrial activities in the United States. Over 1100 coal-fired electric utility steam generating units operate in the United States. These units burned over 1,006.5 million short tons of coal in 2003.⁵³ Even minute concentrations of a chemical in stack emissions can produce seemingly large total emission estimates when individual plant emissions are summed across 1100 units nationwide.⁵⁴

More importantly, EPRI modeling has demonstrated that mercury must be studied and understood on a global scale rather than a national one. About 75% of mercury that deposits in

and transport modeling results often overpredict the amount of mercury that deposits near power plants.

In addition, measurements of speciated mercury in coal-fired power plant plumes as part of the Southeastern Aerosol Research and Characterization ("SEARCH") Program have shown substantially lower ratios of ionic to elemental mercury than what is expected to be emitted based on coal measurements and algorithms developed by EPRI using EPA's ICR data. The results of this work are presented in Attachment 4.

⁵³ Fred Freme, "U.S. Coal Supply and Demand; 2003 Review," 1 (2004) *available at* www.eia.doe.gov/cneaf/ceal/page/special/feature.html.

⁵⁴ For example, EPA's municipal waste combustor standard (Subpart Eb) limits mercury emissions to 80 Mg/m³. One Mg/m³ converts to 0.92 pounds per trillion British thermal units ("lb/Tbtu") (assuming 7% O₂). This equates to a 73.6 lb/Tbtu limit for municipal waste incinerators. By comparison, this is an order of magnitude higher than the MACT limits proposed for electric utility steam generating units. The incinerator limit is higher than the current emissions from any coal fired power plant.

the U.S. comes from natural or foreign sources.⁵⁵ Based on EPRI's analysis of the ICR data, over 56% of the mercury emitted from coal-fired power plants is in the elemental form. This mercury enters the global pool and circulates in the environment for up to a year or more. Only minute amounts deposit near power plants. Significant amounts of the gaseous ionic mercury emitted by coal-fired power plants may be converted to elemental mercury shortly after exiting the stack. This converted elemental mercury also enters the global pool. EPRI modeling work shows that reducing power plant mercury emissions by 70% to 15 tons per year would change mercury deposition in the U.S. about 7%.⁵⁶

The fact that some mercury emitted by coal-fired power plants deposits in the U.S. does not mean that all of that mercury finds its way into humans. Human health concerns are focused on one mercury compound -- methylmercury. None of the mercury emitted from coal-fired power plants is in the form of methylmercury. Mercury emitted from power plants only becomes methylmercury if it first finds its way into a waterbody and is converted to methylmercury. Even then it can take years for the methylmercury to work its way up through the food chain and ultimately find its way to humans.⁵⁷

Thus, a statement that coal-fired power plants are the largest source of mercury emissions in the U.S. does not, in itself, justify a decision to regulate under § 112(n)(1)(A).

⁵⁵ See EPRI Comments at 13.

⁵⁶ See *id.* at 7 and 53, Table B,1-6.

⁵⁷ See *id.* at 20 (the state-of-the-science on mercury cycling is too imprecise to predict either the timing or the magnitude of fish mercury concentration changes due to changes in atmospheric deposition).

c. The Presence of Fish Advisories for Methylmercury Does Not Prove a Risk to Human Health

In the listing decision and the preamble to the proposed rule, EPA cites the existence of fish advisories for methylmercury in 40 or more states as evidence that mercury presents a human health concern in the U.S. Fish advisories, by their nature, are implicitly tied to the RfD EPA or a state sets for a given compound. Thus, if EPA or a state lowers an RfD, the number of fish advisories will likely increase. This is particularly true if the concentration of the compound in fish is near the trigger point for a fish advisory. In the case of methylmercury, the presence or absence of fish advisories is very sensitive around the level of EPA's RfD.⁵⁸

Fish advisories are based on the total mercury loadings in a given waterbody. They do not distinguish among the sources of the mercury entering the waterbody or how much of the mercury in the waterbody came from historical sources. Thus, it does not legally follow that fish advisories result from mercury emissions from coal-fired power plants.

States also do not develop fish advisories using a common methodology. Some states use EPA's RfD; others use the WHO's RfD; while still others use their own unique methodologies. States also use varying assumptions about the frequency at which humans consume fish, the portion size of each fish meal, and the body weight of members of various population groups. In addition, the measurement of mercury levels in fish are not uniform. In some states, a small number of fish measurements can trigger a fish advisory. Thus, while fish advisories may show that levels of a chemical in certain fish are at or above certain thresholds, they do not establish that a health risk exists. Indeed, the primary purpose for fish advisories is to warn the public

⁵⁸ See Whipple, "The Sensitivity of Fish Advisories to Changes in the Reference Dose for Mercury: A Case Study of Eight Plants," Tables 36 and 37 (Dec. 30, 1999) (although the state fish advisors described in the study may have changed since publication, the conclusion that the stringency of advisories is sensitive to RfD remains correct) (Attachment 5).

about undue consumption of fish from given water bodies in an effort to change behavior patterns and thus avoid health issues. Quite simply, the presence of fish advisories does not mean that mercury emissions from coal-fired power plants pose risks to public health.

d. The NHANES Results Should Not Be Misused

In the proposal, EPA notes that the Center for Disease Control (“CDC”) recently assessed mercury concentrations in blood of over 1500 women of childbearing age. Analyses of these data show that about 8% of these women have levels of mercury in their blood that are at or above EPA’s RfD.⁵⁹ Given EPA’s previous comments about how its RfDs should be used and interpreted,⁶⁰ one cannot conclude that these women are at risk. An examination of the NHANES data reveals that most of the women with mercury-in-blood levels above EPA’s RfD are only slightly above the RfD. The woman with the highest tested mercury levels was at about

⁵⁹ 69 Fed. Reg. at 4658. In various forums, this 8% value has been translated into an estimate of 300,000 children born in the U.S. who may be at risk as a result of their mothers’ blood levels being above EPA’s RfD. More recently, a value of 600,000 women exposed at levels above the RfD has been reported in the press and repeated in comments submitted to EPA in this rulemaking docket. This value comes from the remarks by an EPA scientist at the 2004 National Forum on Contamination in Fish in San Diego on January 27, 2004. The views presented were those of an individual scientist and should not be ascribed to EPA, since the Agency has not modified the RfD published on its IRIS database nor has it noticed an intent to do so. This seeming increase in the number of women “at risk” highlights the problems and misuse of EPA’s RfDs. Because EPA’s RfDs are not subject to formal notice and comment proceedings, comments by a single EPA scientist can be misinterpreted to suggest that EPA has revised its RfD.

In fact, the cord blood to maternal blood ratio that is the basis for the EPA scientist’s claim was expressly considered in setting EPA’s current reference dose for methylmercury. The IRIS documentation reveals that EPA decided not to make an adjustment for the ratio but instead to include uncertainties about the relationship in the overall uncertainty factor. *See IRIS Database, Methylmercury, § I.A.3, Uncertainty and Modifying Factors.* Thus, if the EPA’s scientist’s view is accepted as correct, the uncertainty factor for the RfD for methylmercury would need to be reduced by a similar factor. There is no basis for the 600,000 figure.

⁶⁰ *See* Section I.B.1. above.

one-half the BMD. In other words, the reason 8% of the women have blood levels above EPA's RfD is entirely because of the uncertainty factor EPA chose to employ in setting the RfD for methylmercury. Had EPA's reference dose been the same as the WHO's suggested exposure level then less than 2% of the women tested would have had mercury blood concentrations above the RfD. If ATSDR's recommended value was used, the number would drop to well under 1%.⁶¹

Thus, in analyzing the NHANES results, EPA cannot compare them to EPA's RfD as a measure of the risk to public health. Instead, the Agency must consider those results in the context of how EPA developed its RfD and the conservatisms imbedded in that RfD. When viewed properly, the NHANES data do not demonstrate a widespread mercury health concern that warrants the regulation of all coal-fired power plants.

3. EPRI Analyses Show That Significant Reductions in Mercury Emissions from Coal-Fired Power Plants Will Result in Very Little Change in Human Exposures in the U.S.

As noted above, EPA has repeatedly said that it cannot quantify the linkage between mercury emissions from coal-fired power plants and mercury levels in fish. In the preamble to the proposed rule, EPA presents an assessment of the benefits that it predicts will result from its proposed mercury limits.⁶² The vast majority of that analysis focuses on health benefits that will result from reducing SO₂ and NO_x emissions. With regard to mercury, EPA states: "the Agency believes that the key rationale for controlling Mercury is to reduce public and environmental exposure to Mercury, thereby reducing risk to public health and wildlife. Although the available science does not support quantification of these benefits at this time, the Agency believes the

⁶¹ See EPRI, "A Framework for Assessing the Cost-Effectiveness of Electric Power Sector Mercury Control Policies," at D-3 (2003) (Docket No. OAR-2002-0056-2588).

⁶² See 69 Fed. Reg. at 4707-12.

qualitative benefits are large enough to justify substantial investment in Mercury emission reductions.”⁶³ EPA’s speculation about the possible benefits from the control of mercury emissions from coal-fired power plants is not borne out by detailed analyses performed by EPRI.

In May 2003, EPRI released a technical report analyzing the cost effectiveness of the proposed Clear Skies legislation and a hypothetical MACT standard.⁶⁴ The analysis first used a model that simulates electric system operation and decision making to predict how utilities would act to comply with the two regulatory structures. EPRI then used an atmospheric fate and transport model to predict how the resulting changes in mercury emissions would affect a number of receptors in specific source regions. The deposition information was then used to estimate the change in methylmercury exposure to women of childbearing age.⁶⁵ These changes in methylmercury exposure were then compared to the estimated costs of each regulatory scheme.

EPRI’s analyses found that mercury emissions from coal-fired power plants contributed less than 8% of the mercury deposited in the United States. A 10% reduction in national ionic mercury emissions from coal-fired power plants would result in a 0.75% reduction in U.S. mercury deposition; a 10% reduction in national elemental mercury emissions would lower U.S.

⁶³ *Id.* at 4711.

⁶⁴ EPRI, “A Framework for Assessing the Cost-Effectiveness of Electric Power Sector Mercury Control Policies” (2003) (Docket No. OAR-2002-0056-2588). The MACT case modeled by EPRI conservatively assumed a mercury emission limit of 2.2 lb/TBtu for all existing coal-fired units, regardless of the rank of coal burned. This MACT assumption would produce total mercury emissions of about 24 tons per year, which is significantly less than the 34 tons per year EPA has estimated for the MACT limits in its proposal.

⁶⁵ EPRI assumed that there was no time lag between emission reductions from coal-fired power plants and changes in level of methylmercury in fish that are consumed by humans. This simplifying assumption overstates the end effect of any mercury reduction.

mercury deposition by 0.03%. Even if mercury emissions from coal-fired power plants are reduced to 15 tons per year, mercury deposition in the U.S. would only be reduced by about 7%.

As might be expected, this small reduction in mercury deposition in the U.S. has little effect on the exposures of women of childbearing age. The mercury exposure of this population subgroup would only be reduced by 0.5 to 0.75%. The decrease in the fraction of the population predicted to be above EPA's RfD would be reduced by 0.064%. As noted above, the NHANES data show that most of the women who are exposed above the RfD have exposures barely above the RfD threshold. Thus, the small predicted percentage reduction in the population above the RfD reinforces the conclusion that significant reductions in mercury emissions from coal-fired power plant will yield minimal health benefits.

Thus, this rulemaking record does not contain sufficient factual evidence to conclude that mercury emissions from coal-fired power plants present a public health concern.

II. EPA Has Correctly Decided Not to Regulate HAP Emissions Other Than Mercury Nickel

Electric utility steam generating units are treated uniquely under § 112. Congress required all other sources of hazardous air pollutant emissions to be regulated either as major or area sources.⁶⁶ Section 112(d)(1) provides that “[t]he Administrator shall promulgate regulations establishing emission standards for each category or subcategory of major sources and area sources of hazardous air pollutants listed for regulation.” The D.C. Circuit has interpreted this language to oblige EPA to set emission standards for each listed Hazardous Air

⁶⁶ Section 112(c)(1), 42 U.S.C. § 7412(c)(1), requires EPA to develop a list of major source categories and then to regulate those categories under § 112(d), 42 U.S.C. 7412(d). Section 112(c)(3), 42 U.S.C. § 7412(c)(3) requires EPA to list categories of area sources and then regulate those sources under § 112(d)(5), (k), 42 U.S.C. § 7412(d)(5), (k).

Pollutant (“HAP”) that facilities in a source category emit.⁶⁷ For most source categories, § 112 operates in a mechanical way: once the category is classified as one of major or area sources, emission limits are set for all HAPs emitted from sources in that category.

By contrast, the regulation of electric utility steam generating units is governed by the provisions of § 112(n)(1)(A). That subsection requires EPA to “perform a study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units of pollutants listed under subsection (b) of this section after imposition of the requirements of this chapter.” The Administrator is required to consider the results of that study to determine if regulation of electric utility steam generating units is “appropriate and necessary” under § 112. Read as a whole, § 112(n)(1)(A) commands EPA to study the public health effects anticipated to result from the emission of HAPs and then to regulate those HAPs where regulation is “appropriate and necessary” to protect public health. Thus, the factual predicate for any regulatory action by EPA is an initial finding that a HAP presents a public health concern.

In its 1998 Utility Study, EPA identified all of the HAPs emitted by coal-fired power plants, estimated the emissions of each HAP, and analyzed the risk posed by emissions of each HAP using conservative, screening models and assumptions. As a result of that work, EPA decided not to make a regulatory determination as part of the Utility Study.⁶⁸ Instead, EPA offered the general conclusion that mercury from coal-fired power plants is the HAP of “greatest potential concern” and that additional research and monitoring is needed.⁶⁹ As for all other HAPs, EPA found that “[f]or a few other HAPs” some remaining potential concerns and

⁶⁷ See *National Lime Ass’n v. EPA*, 233 F.3d 625, 634 (D.C. Cir. 2000).

⁶⁸ Utility Study at ES-1.

⁶⁹ *Id.*, ES-27.

uncertainties may need further study.⁷⁰ For dioxins and arsenic, EPA noted that screening multipathway assessments suggest potential concern, although EPA acknowledged that further evaluations and review were needed to characterize the impacts of these two HAPs.⁷¹ EPA also noted that nickel emissions from oil-fired plants were of potential concern, but that significant uncertainties exist about the form of nickel emitted.

The December 14, 2000 regulatory decision described the evidence that caused EPA to conclude that “mercury is both a public health concern and a concern in the environment.”⁷² With regard to other HAPs, EPA stated that “arsenic and a few other metals (*e.g.*, chromium, nickel, cadmium) are of potential concern for carcinogenic effects and that dioxins, hydrogen chloride, and hydrogen fluoride are of potential concern.”⁷³ EPA added that “[t]he other HAP[s] studied in the risk assessment do not appear to be a concern for public health based on available information.”⁷⁴ In the preamble to the proposed rule, EPA does not suggest that any of those non-mercury HAPs is a public health concern nor has it offered any factual evidence to support such a conclusion.⁷⁵

⁷⁰ *Id.*

⁷¹ *Id.*

⁷² 65 Fed. Reg. at 79830. As EPA has now acknowledged in the preamble to its proposed rule, § 112(n)(1)(A) only allows EPA to regulate if the Agency identifies a human health concern. A finding that a HAP may pose an environmental concern is not a basis for regulation under § 112(n)(1)(A). UARG’s disagreements with EPA’s conclusion that mercury is a public health concern are presented in Section I above.

⁷³ *Id.* at 79827.

⁷⁴ *Id.*

⁷⁵ EPA’s findings with regard to nickel emissions from oil-fired power plants are discussed in Section V. below.

EPRI also conducted a detailed study of the HAPs emitted by coal-and oil-fired power plants and modeled the risks posed by those HAPs.⁷⁶ That study confirmed EPA’s conclusion that electric utility steam generating unit emissions of non-mercury HAPs do not pose public health concerns.

As a result, the rulemaking record does not establish a public health concern from power plant emissions of non-mercury HAPs. Until such a factual showing exists, EPA does not have legal authority under § 112(n)(1)(A) to regulate those HAPs.⁷⁷

III. General Comments on EPA’s Regulatory Proposals

A. EPA’s Regulatory Options Under § 112(n)(1)(A)

UARG commends EPA for revisiting the wisdom of its December 2000 listing decision and requesting comment on more than one regulatory option. Section 112(n)(1)(A) provides EPA broad authority to craft regulation of electric utility steam generating units to address any health concerns EPA identifies in its Utility Study. It requires EPA to “regulate electric utility steam electric generating units under this section, if the Administrator finds such regulation is appropriate and necessary.” The provision also instructs EPA to develop alternative control strategies for emissions which may warrant regulation. Possible control strategies include a cap-and-trade program, risk-based standards, MACT limits or some hybrid form of these approaches.

⁷⁶ EPRI, “Electric Utility Trace Substances Synthesis Report,” Vols. 1-4 (Nov. 1994), Vol. 1 (Docket No. OAR-2002-0056-2039); Vol. 2 (Docket No. OAR-2002-0056-2279); Vol. 3 (Docket No. OAR-2002-0056-2280); Vol. 4 (Docket No. A-92-55-I-H-294).

⁷⁷ The D.C. Circuit’s decision in *National Lime* does not dictate a different conclusion. In that case, the court’s decision turned on the language of § 112(d)(1). As noted above, Congress did not make electric utility steam generating units subject to that provision. Thus, the court’s decision has no bearing on the interpretation of § 112(n)(1)(A).

EPA's choice of a cap-and-trade program as an alternative to MACT is a good one. As shown by EPA's Acid Rain program, a well constructed cap-and-trade program, with a fair and equitable distribution of allowances, can achieve significant emission reductions in a cost-efficient manner. A cap-and-trade program provides individual units maximum flexibility to reach an emissions cap. It also encourages the development and installation of innovative control technologies. This is because a plant owner will be rewarded through the sale or banking of excess allowances if the innovative technology works, while at the same time the unit would not face the possibility of a shutdown if the technology did not perform as expected because the unit could buy allowances or use banked ones to achieve compliance. Finally, a cap-and-trade program rewards early emission reductions through the use of a banking system.

More detailed comments on EPA's cap-and-trade proposal are contained in Section VI. below.

B. The Timing of Compliance for EPA's Utility HAP Rule and CAIR

Regardless of whether EPA chooses to proceed with a mercury MACT rule or a cap-and-trade program, the timing and implementation of those programs should mesh with EPA's proposed CAIR, assuming that that rule is promulgated.⁷⁸ If EPA promulgates CAIR and a mercury rule, electric utilities will expend large amounts of money to reduce SO₂, NO_x and mercury emissions from their plants. Integrated timing and implementation of these two rules is critical so that utilities can develop plans to limit emissions of these three compounds in the most efficient manner. If the two rules are implemented on different timeframes then severe inefficiencies can result. For example, if the mercury MACT standards require compliance in

⁷⁸ As noted above, UARG's position is that CAIR is premature under the existing provisions of the CAA.

2008 and Phase 1 of the CAIR rule requires compliance in 2010, 2011, or 2012,⁷⁹ then plants may need to install temporary mercury control equipment to meet the mercury limits in 2008 and 2009. This temporary equipment may not be needed in 2010-2012 when scrubbers and selective catalytic reduction (“SCR”) units would be installed for CAIR compliance. This outcome makes no practical sense. EPA must harmonize the timing and implementation of the two rules.

C. Fuel Diversity

At various places in the preamble to EPA’s proposed rule, the Agency concludes that it is not appropriate to consider fuel switching as a compliance option. UARG supports EPA’s conclusion. The CAA was designed to require industrial and manufacturing facilities to reduce their emissions of certain air pollutants. The CAA was not enacted to force large groups of plants to cease operation.⁸⁰ In addition, the CAA favors the development of consistent standards that do not create regional disparities.⁸¹

Fuel switching implicitly favors certain fuel types and sources over others. In many cases, plants cannot readily switch from one type of fuel to another. For plants that cannot switch fuels, there may be no option but to shut down. This result is inconsistent with the goals of the CAA. In addition, a regulatory policy which favors one fuel type over another can have

⁷⁹ As noted above, UARG’s has commented that compliance with Phase 1 of CAIR is not feasible before 2012. For that reason, UARG also has commented that any proposal to accelerate the CAIR Phase I compliance deadline to a date earlier than 2010 would be unsupported.

⁸⁰ *See, e.g.*, H.R. Rep. No. 95-294, at 147 (1977) (stating that the Act is designed to “protect clean air resources while permitting both the economic development needed to assure a safe and secure life for all Americans and the domestic resources development essential for energy independence”).

⁸¹ *See* 69 Fed. Reg. at 4669 (“The EPA feels that the intent of the CAA is to develop standards that, to the greatest extent reasonably possible, are consistent across the industry and avoid actions that create regional disparities.”).

severe impacts on electrical reliability and energy security. Events of the last year have demonstrated the importance of maintaining a reliable electric supply system. They have also raised questions about the availability and cost of natural gas in the United States. Wholesale switching of power generation from coal to natural gas would have severe impacts on the supply and cost of natural gas. Fuel switching is not an appropriate option under either the proposed MACT standards or a cap-and-trade program.

IV. EPA's MACT Proposal for Coal Fired Units

EPA's proposed MACT rule fairly addresses a number of key issues identified by the utility industry during EPA's utility MACT working group meetings. EPA's decision to create subcategories based on coal rank recognizes the inherent differences in the mercury species created by burning coals of different rank. In setting MACT floors, EPA has acknowledged the limited nature of the 1999 ICR stack testing data and has adjusted the floors to account for the large variability in mercury emissions from a coal fired power plant. EPA proposes to judge compliance with the MACT limits over a 12-month period which reflects the fact that the health concerns about mercury exposures are chronic and long-term in nature, not acute. EPA's decision to allow emission averaging within a facility provides utilities flexibility without compromising public health. Finally, given the many questions that remain about the continuous measurement of mercury emissions, EPA's decision to allow a choice between two compliance methods is critical for any emissions regulation.

However, EPA's proposed MACT rule also contains a number of problems which must be modified if EPA proceeds to promulgate a final MACT rule. EPA's proposed MACT limits for new sources fail to reflect all sources of mercury variability and, as a result, are set so low that the construction of new coal-fired units will be difficult, if not impossible. The proposal also fails to include MACT limits based on percentage reductions. Without a percentage

reduction option, many higher mercury content coals may no longer be used. This will result in fuel switching, an outcome the proposal professes to want to avoid. EPA's proposed MACT compliance provisions contain numerous technical and implementation problems and inconsistencies that must be addressed if any MACT rule is finalized. These compliance issues are discussed in Section IV.E. below and in the attached Technical Review Comments by RMB Consulting & Research, Inc. ("RMB") (June 25, 2004) (hereinafter "RMB Technical Comments") (Attachment 6). Finally, there is simply no way for all coal-fired units to comply with EPA's proposed MACT limits within three years. EPA must grant compliance extensions in its final rule.

A. Subcategorization

UARG supports EPA's decision to divide the category of electric utility steam generating units into a number of subcategories. EPA's legal authority to create subcategories is clear in § 112. Section 112(d)(1) provides EPA discretion to distinguish "among classes, types, and sizes of sources within a category or subcategory in establishing standards." Section 112(c)(1) adds that "[t]o the extent practicable, the categories and subcategories listed under this subsection shall be consistent with the list of source categories established pursuant to section 7411 of this title and part C of this subchapter."

Under § 111, EPA has previously subcategorized coal-fired power plants based on the sulfur levels in the coals they burn.⁸² This subcategorization approach was approved by the D.C. Circuit in *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981). In approving EPA's New Source Performance Standard ("NSPS") regulations, the Court recognized that § 111 allowed

⁸² 40 C.F.R. § 60.43a.

EPA “to distinguish among classes, types and sizes within categories.”⁸³ The Court explained that “[o]n the basis of this language alone, it would seem presumptively reasonable for EPA to set different percentage reduction standards for utility plants that burn coal of varying sulfur content.”⁸⁴ Thus, the Court found that EPA could create subcategories based on the type of fuel a unit burns.

EPA’s Utility Study clearly demonstrates that emissions from coal- and oil-fired power plants are markedly different. These differences result from the amount and form of trace substances in each fuel as well as the compounds that are created during the combustion process. Therefore, oil-fired units should be placed in a different subcategory than coal-fired units.

Differences between coal ranks warrant further subcategorization of electric utility steam generating units. Coal is a heterogeneous fuel. Power plants burning different coals produce different forms of mercury. These differences are particularly pronounced for plants burning different coal ranks. Because mercury speciation dictates the level of control that can be achieved using existing air pollution control equipment, different mercury control standards must be established for different coal ranks.⁸⁵

The combustion of coal creates three forms of mercury: elemental, gaseous ionic and particulate. The quantity of each form created is determined by coal chemistry. At present, the relationship between coal chemistry and mercury speciation is not totally understood. It is

⁸³ *Sierra Club v. Costle*, 657 F.2d at 318.

⁸⁴ *Id.*

⁸⁵ As an attached technical memorandum shows, it is difficult for existing boilers to switch from burning one coal rank to another. Lowell L. Smith, “Subcategorization for Establishing Standards of Performance for Mercury for New and Existing Electric Utility Steam Generating Units,” (March 2, 2004) (Attachment 7).

known that chloride content, sulfur content and ash characteristics can all affect mercury speciation. In general, coals with higher chloride contents produce more gaseous ionic and particulate-bound mercury. Bituminous coals have relatively high chloride contents and hence form more gaseous ionic and particulate mercury – in some cases, 80% or more. By contrast, subbituminous and lignite coals have very low chloride contents and much of the mercury produced is in the elemental form – in some cases, more than 90%.

Mercury speciation is critical to understanding the level of control that existing control equipment can achieve. Particulate bound mercury is removed by particulate control devices generally at about the same efficiency as they remove particulate matter. Gaseous ionic mercury is poorly removed by particulate control equipment, but is captured by wet or dry scrubbers. The level of capture varies depending on the amount of ionic mercury that is reconverted to elemental mercury within the scrubber. Scrubbers have been shown to obtain up to 80-90% removal of gaseous ionic mercury. Neither particulate removal devices nor scrubbers remove significant amounts of elemental mercury. A limited number of tests have shown that SCRs may convert some amount of elemental mercury to gaseous ionic mercury in bituminous coal plants.⁸⁶ This gaseous ionic mercury might then be removed by a scrubber but questions remain about whether some of the ionic mercury reduces to elemental mercury in the scrubber. Limited tests have shown that SCRs are not effective in converting elemental mercury to ionic mercury in plants burning subbituminous coals.⁸⁷ The testing of SCRs for mercury conversion has been very

⁸⁶ See EPRI, “Impact of NO_x Controls on Mercury Controllability,” EPRI Report No. 1007221 (July 2002) (Docket No. A-92-55-II-I-18); EPRI, “Evaluating the Effects of Selective Catalytic Reduction and Ammonia on Mercury Speciation and Removal,” EPRI Report No. 1005230 (Dec. 2001) (Docket No. A-92-55-II-I-19).

⁸⁷ *Id.*

limited. Numerous questions remain about the level of conversion that occurs for a given catalyst configuration and about the lifetime of the catalyst for mercury conversion. Selective non-catalytic reduction (“SNCR”) units have not been effective in converting elemental mercury to ionic mercury. Thus, the differences in emission characteristics between coals of different rank dictate that different MACT limits must be established for each coal rank.⁸⁸

UARG has long contended that fluidized bed combustion (“FBC”) units and integrated gasification combined cycle (“IGCC”) units employ fundamentally different processes than conventional boilers⁸⁹ and should be placed in their own subcategories. FBCs combust relatively large coal particles in a bed of sorbent or inert material. FBCs operate at lower temperatures than conventional boilers and have much longer fuel residence times. The design, construction and operation of FBCs are different than conventional boilers.⁹⁰ Indeed, the largest FBC has a nameplate capacity of about 300 megawatts while the largest conventional boilers have nameplate capacities of around 1300 megawatts.

⁸⁸ EPA has requested comment on whether bituminous and subbituminous units should be placed in the same subcategory. *See* 69 Fed. Reg. at 4677. In requesting comments, EPA notes that some industry sources claim that such an approach would “allow greater fuel choice flexibility.” UARG strongly disagrees with this claim. Placing bituminous and subbituminous units in the same subcategory ignores the fundamental differences in the mercury species created during the combustion of each fuel. A single subcategory would greatly decrease fuel choice flexibility. A MACT standard for a combined category would be based solely on the performance of bituminous units. Subbituminous would face a difficult, if not impossible, task of meeting such limits. Similarly, the use of coal blends would be discouraged if the two coal ranks were combined.

⁸⁹ Conventional boilers burn pulverized coal and use burners that are positioned in the lower to middle sections of the furnace. Burner types include wall-fired, tangentially-fired, and cyclone.

⁹⁰ *See* J.E. Cichanowicz, “Assumptions Adopted By EPA Proposal Regarding the Feasibility of Mercury Controls for MACT Application,” Section 3 (June 25, 2004) (Attachment 8) (hereinafter “Cichanowicz Technical Comments”).

EPA recognizes these fundamental differences between FBCs and conventional boilers in the proposed rule.⁹¹ However, EPA has not proposed to create a separate subcategory for fluidized bed units for either existing or new units. EPA reaches this conclusion because it finds that “the Mercury emissions test results for FBC units were not substantially different from those at similarly-fueled conventional-fired units.”⁹² This logic may make sense for existing units, but it does not for new units. For existing units, EPA is required to set MACT floors based on the best performing 12% of all units in the category. Thus, existing source MACT floors represent an average of the performance of a number of units. Differences among units are less important, particularly if the performance of units are truly similar. By contrast, §112(d)(3) requires that new source MACT limits “shall not be less stringent than the emissions control that is achieved in practice by the best controlled similar source.” The focus of this subsection is on a single source, not a group of sources. As explained above, FBCs are not “similar” to conventional boilers. Thus, for new units, EPA should add a separate subcategory for FBCs.⁹³

IGCC units consist of two distinct parts: a gasifier and a combined cycle unit. IGCCs do not burn coal in its solid form, rather the coal is converted to a combustible gas and that is then burned in a turbine. The synthetic gas is cleaned and conditioned before being burned in a gas turbine. IGCCs are totally different processes than other electric utility steam generating units. UARG agrees with EPA proposal to create a separate subcategory for these units.⁹⁴

⁹¹ See 69 Fed. Reg. at 4666.

⁹² *Id.*

⁹³ See RMB Technical Comments, at 3-3 (Attachment 6).

⁹⁴ See 69 Fed. Reg. at 4662-63.

UARG believes that units burning coals of more than one rank should not be placed in a separate subcategory. There are large differences in the way plants burn coals of more than one rank. Some plants alternate between burning coals of one rank and then another. Others blend coals of two ranks. The composition of coal blends vary over a broad range. Some units burn large percentages of bituminous coal with small amounts of subbituminous; others burn almost a 50:50 blend; while still others burn predominantly subbituminous coal with a little bituminous. These differences argue against a separate subcategory for these units.

B. MACT Floors

UARG is generally supportive of the MACT floors EPA has proposed for existing sources. UARG's primary concern with those limits is that EPA did not include the percentage reduction option supported by UARG during EPA's utility MACT working group meetings. UARG believes that EPA's proposed new source MACT limits are unacceptably low and fail to account for all sources of variability. If the new source MACT limits remain as proposed, they would effectively exclude the use of most coals in the United States and make the construction of new coal-fired units difficult, if not impossible.

1. The Proposed Existing Source MACT Floors

EPA's proposed MACT floors are based on data collected as part of EPA's 1999 ICR to electric utility steam generating units.⁹⁵ These data have limitations. EPA's ICR required all facilities to sample and analyze every sixth shipment of coal for mercury content and a number of other properties. In addition, approximately 80 plants were required to conduct mercury

⁹⁵ UARG agrees with EPA's conclusion in the preamble to the proposal that no single control technology can be identified as "best" for the top units. 69 Fed. Reg. at 4671. No existing control equipment installed on coal-fired power plants was designed for mercury removal. As a result, mercury removal efficiencies have more to do with fortuitous combinations of equipment and coal chemistry than the design of existing control equipment.

sampling in the stack as well as before the last control device. Stack sampling was required over a two- or three-day period using the Ontario Hydro method to provide mercury speciation information. Previous EPRI and Department of Energy (“DOE”) sampling efforts had shown that while the Ontario Hydro method is the best available method for obtaining mercury speciation results, it is difficult to use, even by experienced sampling crews.

The limitations of the ICR tests become apparent when one examines the results. The results reveal: (1) large differences among the results of the two or three Ontario Hydro tests at a given facility, (2) large differences in results between plants having the same boiler configurations and control equipment, (3) negative removal efficiencies in more than 25% of the ICR tests,⁹⁶ and (4) questionable mercury data at the inlet of the last control device because of imperfect sampling locations and large amounts of particulate matter in the gas stream. As a result, while the ICR data base may be more extensive than other data sets EPA has used to set other MACT floors, it has important limitations and it cannot be used, without adjustments. In particular, the ICR data are a snapshot of a plant’s operation. They show the level of mercury control accomplished during two or three days of operation at a given facility. They do not provide insights into the level performance a given unit can achieve over long periods of time burning different coals.⁹⁷

The short-term nature of the ICR results was demonstrated repeatedly during the meetings of EPA’s Utility MACT Working group. At the December 18, 2001 meeting, EPRI

⁹⁶ A negative removal efficiency results when the amount of mercury exiting the stack exceeds the amount of mercury in the coal.

⁹⁷ Most coal-fired power plants do not burn coal from a single source. Many plants burn coal that is purchased on the spot market. Plants can burn coal coming from 10 or more different sources.

presented an analysis of the 1999 ICR stack sampling data and described how those data could be used to develop emission correlations depending on the characteristics of the coal being burned and the control equipment installed on a given unit.⁹⁸ UARG presented a number of analyses of the “best performing” units during the ICR testing which made use of the EPRI emission correlations and the coal data that were collected in Part 2 of the 1999 ICR at those units.⁹⁹ Basically, for the best performing units, a mercury emission rate was calculated for each coal sample collected during the 1999 ICR. This year’s worth of mercury emission estimates were then tabulated to produce a cumulative distribution of a given plant’s 1999 mercury emissions. These analyses showed that mercury emissions from the best performing units could vary by more than an order of magnitude throughout the year. The analyses also confirmed the random nature of the ICR results. For some of the “best performing” units, the ICR testing did not take place on a “normal” day, instead, testing occurred on one of that unit’s best days of mercury emissions. For other units that one would not place among the top 12% based on ICR results, the cumulative distributions show those units were tested on a days when mercury emissions were higher than normal.

This large predicted variability in mercury emissions from a given coal fired unit was confirmed by EPRI’s Continuous Emission Monitoring (“CEM”) testing that was conducted for 30 days or more. These results were presented to EPA’s Utility MACT working group on April

⁹⁸ Chu, “EPRI ICR Data Analysis” (Dec. 18, 2001) (Docket No. A-92-55-II-E-19); *see also* EPRI, “An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants,” EPRI Report No. 1000608 (Oct. 2000) (Docket No. A-92-51-II-A-1).

⁹⁹ UARG, “Addressing Variability in Mercury Stack Emissions” (Dec. 18, 2001) (Docket No. A-92-55-II-E-20).

3, 2002.¹⁰⁰ Later results from the State of Massachusetts also confirm the significant variability in mercury emissions from a given coal-fired power plant.¹⁰¹

The MACT floors for coal-fired electric utility generating units must account for the large variability in mercury emissions that occurs at coal-fired units. The CAA requires MACT floors for existing units to be set at the “average emission limitation *achieved* by the best performing 12 percent of existing sources.”¹⁰² A key issue in applying this CAA dictate is how one determines the level of emission limitations a given unit “achieves.” The D.C. Circuit has addressed the question in several decisions. The court has said that the best performing plant must achieve a given level of performance “under the most adverse circumstances which can reasonably be expected to recur.”¹⁰³ Stated differently, EPA must identify the level of

¹⁰⁰ EPRI, “Long-Term Mercury Emissions Variability” (Apr. 3, 2002) (Docket No. A-92-55-II-E-45); UARG, “Variability in Hg Emissions Based on SCEM Data” (Apr. 3, 2002) (Docket No. A-92-55-II-E-46).

¹⁰¹ See Weber, Massachusetts Multi-Pollutant Power Plant Regulations (Mar. 4, 2003). The Massachusetts presentation included quarterly sampling data from the Brayton Point and Salem Harbor coal-fired generating stations. These data show mercury emission variability of up to a factor of 14 over four quarterly tests. More interestingly, the data reveal that the Salem Harbor unit, which had some of the lowest reported emissions during the 1999 ICR tests, would have been categorized as a plant with “normal” emissions had some of its quarterly test results occurred during the three days of ICR testing. By contrast, the Brayton Point unit had 1999 testing results that placed it well outside the top 12% of all plants tested during the ICR. Yet one set of quarterly results reported by this unit under Massachusetts regulations would have placed it among the top 12%.

¹⁰² CAA § 112(d)(3), 42 U.S.C. § 7412(d)(3) (emphasis supplied).

¹⁰³ *National Lime Ass’n v. EPA*, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980); see also *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999).

performance that the best plants achieves virtually all the time.¹⁰⁴ The three days of ICR testing do not demonstrate the level of performance a plant can achieve over the long term.

The variability in mercury emissions can result from a number of factors including: (1) the characteristics of the fuel being burned, (2) the operating conditions of the unit, and (3) the sampling and analytical test methods used to measure mercury emissions. There are a number of ways to adjust the ICR data to account for these sources of variability. In the proposed rule EPA has offered one approach¹⁰⁵ and discusses another offered by DOE.¹⁰⁶ During EPA's utility MACT working group meetings, UARG and WEST Associates also offered two other approaches for addressing variability. Each of these approaches is a valid way to address variability; each method has some advantages and disadvantages when compared to the others.¹⁰⁷

¹⁰⁴ *Sierra Club v. EPA*, 167 F.3d at 665 (“if an emissions 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. This only results if ‘achieved in practice’ is interpreted to mean ‘achieved under the worst foreseeable circumstances.’”)

¹⁰⁵ Memorandum from William H. Maxwell to the Utility MACT Project Files, “Analysis of variability in determining MACT floor for coal-fired electric utility steam generating units” (Nov. 26, 2003) (Docket No. OAR-2002-0056-0123).

¹⁰⁶ L. D. Carter, U.S. DOE, “Incorporating Variability in Setting MACT Floors” (Dec. 9, 2003) (Docket No. OAR-2002-0056-0019). In the proposed rule, EPA requests comments on the relevance of the D.C. Circuit's *Cement Kiln Recycling Coalition* decision to DOE's variability approach. DOE's approach comports with the D.C. Circuit's decision. At base, the DOE approach focuses on the performance of the best units but assumes that those units can burn coal from any source in a given coal rank, not just the coals that unit burned during the 1999 ICR testing. DOE's approach is analogous to EPA's use of worst-case test burn data to derive the floors for hazardous waste combustors. In *Cement Kiln*, the D.C. Circuit rejected Sierra Club's challenge to EPA's worst case approach, finding that Sierra Club had offered no basis for concluding that EPA's approach failed to predict the performance of the best units under the “worst reasonably foreseeable circumstances.” *Cement Kiln Recycling Coalition v. EPA*, 255 F.3d 855, 867 (D.C. Cir. 2001).

¹⁰⁷ See RMB Technical Comments, Section 4 (Attachment 6).

In general, these four different variability approaches produce similar MACT floors for the different coal ranks. If promulgated, each would reduce total mercury emissions from coal-fired power plants from 48 tons per year to around 30 to 34 tons per year. This level of mercury emissions under the MACT provisions makes practical sense when one considers the species of mercury that are currently being emitted from coal-fired power plants. UARG's analysis of the ICR data using the EPRI correlation factors estimates that 45.6 tons of mercury were emitted from coal-fired power plants in 1999. Of this total, 26.7 tons were in the elemental form. EPA's estimates are similar. EPA estimates mercury emissions from all coal-fired power plants totaled 48 tons in 1999. EPA estimates that 26.1 tons of this total was in the form of elemental mercury.¹⁰⁸ Existing control technologies at even the best controlled plants do not capture elemental mercury to any appreciable degree. Thus, this 26 tons of elemental mercury can be viewed as what remains after the maximum amount of mercury reductions that could be achieved using existing control equipment. But the best controlled plants do not capture 100% of all non-elemental forms of mercury. If one conservatively assumes that 90% of the non-elemental forms are captured by the best units then applying this assumption to all coal-fired power plants produces an estimated emission of 1.9 tons of non-elemental mercury. Adding the 1.9 tons of non-elemental mercury to the 26.7 tons of elemental mercury indicates that any MACT floor should not be more stringent than around 28.6 tons annually. If 80% control of non-elemental forms of mercury is assumed then the MACT floor increases to 30.5 tons. All four variability approaches produce MACT floors that are reasonable.¹⁰⁹

¹⁰⁸ See 69 Fed. Reg. at 4691; *see also* "Emissions of Mercury by State," *available at* www.epa.gov/hn/atw/combust/utittox/stxstate2.pdf.

¹⁰⁹ This exercise also shows why the MACT floor levels advocated by environmental groups (5 tons) and state local regulators (10 tons) are unrealistically low and rest on

(continued...)

UARG believes that any MACT floor should provide a unit the option of choosing between alternative standards based on either a stack limit or a percentage reduction. An alternative standard is needed to address the wide variations in mercury levels in coal. An example is helpful to illustrate this point. Assume that the MACT limit for existing bituminous coal units is 2.0 lb/TBtu. The Part II ICR data show that mercury concentrations in bituminous coals ranged from 2.3 to 20.6 lb/TBtu at the 5th and 95th percentiles of the data.¹¹⁰ If a plant is burning coal with a concentration of 8.0 lb/TBtu, then that plant needs to achieve 75% control over the course of a year to meet the 2.0 lb/TBtu limit. If we instead assume the plant burns a coal with a mercury concentration of 20 lb/TBtu, then the plant would need to achieve reductions of 90% over the course of a year to meet the limit. Providing an alternative standard avoids inequities based on the mercury content of coal burned and is consistent with EPA's stated desire of not favoring certain fuels over others.

UARG continues to believe that the MACT floor limits it offered during the EPA utility MACT working group meetings are reasonable and address the variability in mercury emissions from coal-fired power plants. UARG urges EPA to reconsider those limits if it moves forward with promulgating a final MACT rule.

UARG agrees with EPA's approach for setting MACT limits for existing units that burn more than one rank of coal. The use of a weighted average is a reasonable way to address the

unsupportable assumptions about the level of control "achieved in practice" by the best performing units.

¹¹⁰ The entire range of the mercury concentration in bituminous coal from the Part II data was 0.07 to 103.81 lb/TBtu. EPA, "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report," at 2-25 (Apr. 2002).

differences between coal ranks. Calculation of this weighted average on a monthly basis is also reasonable.

UARG concurs with the MACT floor EPA has proposed for existing IGCC units. Only two IGCC units are in operation and each was tested during the 1999 ICR. The methodology EPA used to account for variability from these units is consistent with the one EPA used to set the MACT floors for other subcategories.

2. New Source MACT Limits

EPA's proposed new source MACT limits fail to account for all sources of variability and, as a result, are set far too low. Indeed, if left unchanged, the proposed new source limits will make it difficult, if not impossible, to construct a new coal-fired power plant in the United States. A simple example demonstrates the unwarranted stringency of EPA's proposed new source MACT limits. EPA's proposed new source MACT limit for bituminous coal units is 6×10^{-6} pounds per megawatt hour ("lb/MWh") (or 0.6 lb/TBtu).¹¹¹ As part of EPA's 1999 ICR, coal-fired power plants were required to collect and analyze every sixth shipment of coal. In all, 27,793 bituminous coal samples were analyzed and reported to EPA. The range of mercury concentrations in these samples ranged from 0.07 to 103.81 lb/TBtu. The mean value of these bituminous coals was 8.61 lb/TBtu.¹¹² If one optimistically assumes that a new unit can achieve

¹¹¹ EPA's proposed MACT limits for new units are all in the form of output-based limits. As EPA notes in the preamble to the proposed rule, however, all of the data used to develop the MACT floors were in an input-based format so EPA used a conversion factor to translate the input-based values into an output-based limit. *See* 69 Fed. Reg. at 4678. The 0.6 lb/TBtu value comes from the EPA memorandum entitled "Analysis of variability in determining MACT floor for coal-fired utility steam generating units" (Nov. 26, 2003).

¹¹² *See* EPA, "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers," at 2-25 (Apr. 2002) (Docket No. A-96-47-II-A-12) (*see also* Docket No. OAR-2002-0056-0463).

90% control of mercury,¹¹³ then a new plant could not burn coal with a mercury concentration above 6.0 lb/TBtu and still meet the new source limit for bituminous coals. Only 37.8% of the bituminous coals sampled during the 1999 ICR had concentrations of 6.0 lb/TBtu or below. If one instead assumes that a new source can achieve 80% control consistently, then bituminous coal above 3.0 lb/TBtu could not be burned. Only 8.3% of the 1999 bituminous coal samples were at or below 3.0 lb/TBtu.¹¹⁴ Thus, EPA's proposed limits would prevent the use of the vast majority of bituminous coals in new bituminous coal-fired units.

There are two reasons why EPA's new source MACT limits are too low: (1) EPA has based its new source limits on units that are not "similar" to most new coal-fired units, and (2) EPA has failed to account for the range of coals a new unit may burn.¹¹⁵ Section 112(d)(3) of the CAA requires MACT floors for new units to reflect "the maximum degree of reduction in emissions that is deemed achievable for new sources in a category . . . [and it] shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source." As noted above, the D.C. Circuit has interpreted this language to require EPA to ensure

¹¹³ At numerous places in the preamble to the proposed rule and supplemental notice, EPA says that 90% control is not presently achievable. *See* 69 Fed. Reg. at 4667; 69 Fed. Reg. at 12403 (Mar. 16, 2004).

¹¹⁴ Similar examples can be developed for subbituminous and lignite units. The proposed new source limit for subbituminous units is 20.0 lb/MWh (or 1.9 lb/TBtu). If a 70% mercury control efficiency is assumed for new units, then only coals under 6.33 lb/TBtu could be burned which comprise 67.2% of the 1999 subbituminous coal samples. If 50% control is assumed, the acceptable concentration of mercury in coal drops to 3.8 lb/TBtu; 28.6% of subbituminous samples are below this value. For lignite units, the proposed new source limit is 62 lb/MWh (or 5.8 lb/TBtu). If 70% control is assumed, coals below 19.3 lb/TBtu could be burned (or 87.2% of 1999 lignite samples). If 50% control is assumed, lignite coals below 11.6 lb/TBtu could be burned (or 70.7% of lignite samples). Although these examples are not as extreme as the one for bituminous units, they still demonstrate that EPA's proposed new source limits will exclude the use of a number of subbituminous and lignite coals.

¹¹⁵ *See* RMB Technical Comments, Section 3 (Attachment 6).

that the MACT floor is achievable “under the most adverse circumstances which can reasonable be expected to occur.”¹¹⁶ Therefore, the new source MACT floor must reflect how the best controlled similar source would perform under the worst reasonably foreseeable circumstances, including using a variety of different fuels. At a minimum, all new source MACT limits should offer alternative standards based either on a stack limit or a percentage reduction.

EPA’s proposed MACT limit for new bituminous coal-fired units does not reflect the level of performance “achieved in practice” by the best controlled “similar” source. EPA’s rulemaking proposal does not identify the best controlled bituminous unit. An EPA memorandum in the rulemaking docket reveals that Stockton Unit 1 was the best controlled unit.¹¹⁷ Stockton Unit 1 is a 55 MW FBC unit. It is dissimilar in its size and combustion process from most new coal-fired boilers. EPA has itself recognized the fundamental differences between FBC units and conventional boilers. In addition, Stockton simultaneously burns a mixture of western bituminous coal, petroleum coke, and tire-derived fuel.¹¹⁸ As a result, the Stockton unit is not “similar” to other new conventional coal-fired boilers and it should not be selected as the basis for setting the MACT floor for new bituminous coal units.¹¹⁹

¹¹⁶ *National Lime Ass’n*, 627 F.2d at 431 n.46.

¹¹⁷ See EPA, “Analysis of variability in determining MACT floor for coal-fired electric utility steam generating units” (Nov. 26, 2003). (Docket No. OAR-2002-0056-0006).

¹¹⁸ “Source Test Report, 1999 Mercury Speciation Study, Stockton Cogen Company” (Jan. 2000).

¹¹⁹ If EPA were to create a category of new FBCs, as UARG has suggested, then Stockton could be considered as the best controlled unit for that subcategory. However, the unusual variety of fuel burned by that facility makes it difficult to conclude that the facility is “similar” to other units.

Another of the four top-performing bituminous coal-fired power plants identified by EPA is so dissimilar from most new conventional boilers that it should not be selected as the basis for setting a new source MACT limit. Dwayne Collier Unit 2B is a traveling grate furnace. A traveling grate furnace is an old design that is a relatively inefficient combustion technology. Traveling grate furnaces comprised only about 0.3% of the coal-fired units that responded to Part 1 of EPA's 1999 ICR. While little is technically known about how these units create the various forms of mercury as compared to pulverized units, the fundamental differences between this technology and pulverized coal boilers lead to the conclusion that stoker units are not "similar" sources.

The other two top-performing units identified in EPA's variability memorandum are Valmont Unit 5 and Mecklenburg Unit 1. Both of these units are conventional, pulverized coal-fired boilers. For these units, the question becomes whether they burned coals typical of the worst case coal that bituminous units could burn. In the case of Valmont, the answer is definitely no. Valmont burns a western bituminous coal mined in Colorado. Coal from that mine has some of the lowest mercury content of any bituminous coal tested during Part 2 of EPA's 1999 ICR. The highest mercury coal value reported by Valmont during 1999 was 0.067 ppm. During the three days of ICR testing at this facility the mercury content of the coal ranged from 0.96 lb/TBtu to 5.24 lb/TBtu. By contrast, the mean concentration of 28,000 bituminous coal samples analyzed in 1999 was 0.112 ppm. The concentration of bituminous coal tested at the 97.5th percentile of the Part 2 ICR data was 0.30 ppm -- or 4.5 times higher than the highest mercury content coal burned at Valmont. One way to reflect the "most adverse circumstance which can reasonably be expected to occur" at a unit like Valmont that burns a low mercury content coal would be increase the estimated emissions for that unit by factor that accounts for

the difference between the highest mercury concentration of the fuel burned at Valmont and the mercury concentration in all bituminous coals.

During ICR testing, the Mecklenburg unit had a higher 97.5th percentile emission rate than the Valmont unit -- 1.80 lb/TBtu versus 0.69 lb/TBtu. However, the Mecklenburg facility burned bituminous coals having far higher mercury concentrations than those burned at Valmont. Thus, if Mecklenburg is used to set the new source MACT limit for bituminous units, the limit would be around 20×10^{-6} lb/MWh rather than the 6.0×10^{-6} lb/MWh.

EPA's new source MACT limit for subbituminous units is also too low. EPA's new source MACT limit for subbituminous units is based on Clay Boswell Unit 2. There are several problems with the use of the Clay Boswell unit to set the new source MACT limit for subbituminous units.¹²⁰ First, the high mercury removal rates found during ICR testing at the Clay Boswell unit are suspect when one compares them to other subbituminous units employing identical control technologies. The ICR results for Clay Boswell indicate an average mercury removal efficiency of greater than 82%. The Comanche unit, which is equipped with similar control equipment, had a removal efficiency of 62%. The Craig Unit 3 with similar control equipment plus a spray drier had an average removal efficiency of 36%. Second, the analysis EPA used to derive the 97.5th percentile stack emissions for Clay Boswell assumed a constant mercury removal efficiency. It did not account for the effects of chlorides on mercury emissions.¹²¹ Because EPA's analytical method did not account for a key variable in mercury emissions, it has understated the variability in emissions at that unit. Third, the coal burned at

¹²⁰ See RMB Technical Comments, at 3-4 (Attachment 6).

¹²¹ This is true for each of the four subbituminous plants EPA identified as a "best performers."

Clay Boswell Unit 2 in 1999 had a mercury concentration of 9.7 lb/TBtu at the upper 95th percentile. By comparison, the upper 95th percentile value for all subbituminous coals was 12.5 lb/TBtu. Thus, at a minimum, the Clay Boswell emission value should be adjusted upward by a factor of 1.29 to account for this difference in mercury coal concentration. The new source MACT limit for subbituminous units should be at least 26×10^{-6} lb/MWh.

EPA's new source MACT limit for lignite units is based on the ICR results from Stanton Station Unit 1. This Stanton unit, like all of the top five performing lignite units, burns North Dakota lignite. The mercury concentrations in North Dakota lignites are very different than those in Texas lignites. The upper 97.5th percentile mercury levels in North Dakota and Texas lignites are 17.6 and 38.5 lb/TBtu, respectively. Thus, EPA should modify its new source MACT limit for lignite units by either adjusting the value to account for the higher mercury levels in Texas lignite or by creating a separate new source category for Texas lignites.

The practical effect of EPA's proposed new source MACT limits is that it will be virtually impossible to construct a new coal-fired unit and be sure you will meet these MACT limits. Several new coal-fired units are in the process of seeking operating permits. These units have contacted equipment vendors seeking guarantees that given control equipment will achieve certain levels of mercury control. To date, the vendors have either refused to offer guarantees stating, for example, that the goal of their mercury control technology is 90% but that the technology is not mature enough to allow the company to commit to such a guarantee, or have offered guarantees of control levels of up to 80% and then offered those guarantees only as to the ionic forms of mercury. Given the substantial compliance questions that exist about how new units will comply with EPA's new source limits, financial institutions have shown a reluctance to

provide financing for these units. EPA's new source MACT limits for coal-fired boilers are too low and must be revised.

EPA's new source MACT limit for IGCC units specifies a 90% reduction based on an assumption that all new units will include a carbon bed between the gasifier and turbine.¹²² EPA's 90% assumption is based on very limited data and it is not clear whether 90% control can be achieved over the long-term. In addition, high removal efficiencies by a carbon bed are highly dependant on the temperature of the manufactured gas entering the bed. As temperatures increase, the mercury removal efficiency of the bed falls. IGCC is a developing technology. Some developmental applications of IGCC do not cool the gas exiting the gasifier. For those units, a 90% mercury removal assumption is inappropriate. Thus, given the state of IGCC development it is premature to assume all new units can achieve 90% mercury control.

C. EPA Correctly Decided Not To Change the MACT Floors as a Result of Its Beyond-the-Floor Analyses

UARG agrees with EPA's determination that available technologies and work practices do not provide a viable basis for establishing standards beyond the MACT floors.¹²³ In the preambles to the proposed rule and supplemental notice, EPA discusses the status of mercury control technologies and why it is premature to assume that 90% control of mercury emissions is currently achievable.¹²⁴ UARG agrees that 90% control of mercury emissions is not achievable with any currently available technology.¹²⁵

¹²² See proposed 40 C.F.R. § 63.9990(b); 69 Fed. Reg. at 4679.

¹²³ See 69 Fed. Reg. at 4675.

¹²⁴ *Id.* at 4679-80; 69 Fed. Reg. at 12402-03.

¹²⁵ See Cichanowicz Technical Comments, Sections 2 and 6 (Attachment 8).

Any assessment of mercury control technologies must distinguish between technologies that are commercially available and those that are still in development. For a technology to be commercially available, it must be able to control mercury emissions from plants burning different coal ranks and having different boiler types. In addition, a few isolated tests or demonstrations are insufficient to conclude that a technology is commercially available. A technology needs to be installed in full-scale applications at a number of sites and operated over extended periods of time before it can be viewed as commercially available. In other words, a technology is not commercially available just because a vendor is willing to sell it. Commercial availability requires that most of the key engineering questions about the technology need to have been previously resolved. A technology is not commercially available if a company installs it knowing that many problems will need to be solved as experience is gained with the technology -- that is the definition of a prototype unit, not a commercially available one. Another indicia of commercial availability is when a vendor is willing to guarantee a certain level of performance and then backs that guarantee with a significant financial commitment.¹²⁶

Activated carbon injection (“ACI”) is not a commercially available technology. Bench and pilot-scale tests have identified a number of the key variables associated with this technology but, to date, there has been very limited full-scale testing of this technology. The four full-scale ACI tests were all of very limited duration and were conducted at units that are not representative of most coal-fired units. These tests produced wide variations in mercury control. Thus, while

¹²⁶ Several commenters have suggested that some case-by-case MACT determinations under § 112(g) have established that given control technologies are commercially available and that certain levels of control are achievable. In fact, the § 112(g) determinations for new coal-fired units have included an “escape clause” which mandates the operator to make a good-faith effort to operate a new control technology. As a consequence, these units do not bear the full risk of a new control technology. The § 112(g) permits do not establish that the new technology will achieve a given level of control over the long-term.

some ACI results are promising, many questions remain about the test results and the level of performance the technology can achieve over the long-term. ACI is not a commercially available technology and can not serve as the basis for beyond-the-floor limits.

A number other sorbents have been offered as possible alternatives to activated carbon. While these sorbents offer the possibility of improved mercury capture, none has been demonstrated at full-scale to remove mercury with acceptable balance-of-plant impacts. Many questions remain about the effectiveness, availability and cost of these sorbents.

SCRs have also been offered as a possible way to enhance the mercury removal efficiency of flue gas desulfurization (“FGD”) equipment. In theory, SCR units oxidize elemental mercury and these oxidized forms of mercury are then removed by FGDs. Limited mercury testing has been done on units equipped with SCRs and FGDs. The results of those tests are inconclusive.¹²⁷ At some bituminous coal plants, SCRs have been shown to increase the amount of oxidized mercury in the flue gas. However, those increases have changed over time raising questions about how factors like catalyst age, space velocities, the volume of catalyst, and other compounds in the flue gas affect elemental mercury conversion. Tests on SCR-equipped units burning subbituminous coals have shown less elemental mercury conversion than bituminous units and very rapid declines in mercury oxidation as the catalyst ages. No SCR tests have been performed on lignite units, so it is impossible to assess the performance of SCR on those units. Questions remain about whether lignite coals will respond like bituminous or subbituminous coals or whether they will have their own unique response. SCR research

¹²⁷ See EPRI, “Impact of NO_x Controls on Mercury Controllability,” EPRI Report No. 1007221 (July 2002) (Docket No. A-92-55-II-I-18).

remains a work-in-progress. Until questions about the effectiveness of SCR units are answered, they cannot form the basis for beyond-the-floor limits.¹²⁸

EPA has also requested comments on whether any pre-combustion technologies have been demonstrated to reduce mercury emission levels. The short answer to this question is no.¹²⁹ Work on several pre-combustion control options have been abandoned due to unfavorable economics. Other approaches have technical problems that must be resolved, including problems with bulk handling and storage due to instability (spontaneous combustion) and dust control. One other option is still in development and has yet to be shown to be technically and economically attractive in a full-scale application.

D. Form of Standard

As noted above, UARG believes that any MACT based limit should be in the form of an alternative standard that provides a unit the choice of complying with either a stack limit or a percentage reduction limit. An alternative standard is the best way to address the differences in the mercury content within a given coal rank and to ensure that certain coal seams are not favored over others.

In the MACT proposal, EPA has proposed a choice of either an input-based or an output-based stack limit for existing units. For new units, EPA has proposed only an output-based limit. As UARG noted during the EPA utility MACT working group meetings, output-based limits are unlikely to result in greater energy efficiency from coal-fired units. Fuel costs are the major

¹²⁸ Test of SNCR units have shown little or no oxidation of elemental mercury. EPA's statement in the preamble to the contrary is simply not supported by any test data. See EPRI, "Impact of NO_x Controls on Mercury Controllability," EPRI Report No. 1007221 (July 2002) (Docket No. A-92-55-II-I-18).

¹²⁹ See Cichanowicz Technical Comments, Section 2 (Attachment 8).

component in the cost of producing electricity. Thus, electric utilities already have great incentives to see that heat energy from combustion is efficiently converted into electricity. Imposing an output-based limit will not change the way in which electric utility steam generating units are operated.

Regardless, UARG supports EPA's proposal to allow existing units to comply with either an input-based or an output-based limit.¹³⁰ UARG also concurs with EPA providing only an output-based limit for new units. UARG's support for new and existing output-based units is based on the use of gross energy output as the measure of compliance, not net energy output.¹³¹

UARG supports the use of gross energy output for a number of reasons. The use of gross output is consistent with other regulatory limitations, such as the NSPS for NO_x. A gross output standard takes into account the inherent differences in heat rates in different types of coal better than a net energy output standard.¹³² Furthermore, gross energy output is measured directly by units as a part of the Acid Rain requirements. By contrast, net energy output is calculated by subtracting the electric energy used by boiler and plant auxiliaries from the gross output. Two difficulties exist in determining the electric energy used by the boiler and plant auxiliaries: (1)

¹³⁰ All of the data used to develop EPA's proposed MACT limits were input-based. Thus, to develop output-based limits, EPA had to employ efficiency conversion factors. The factors chosen by EPA -- 32% for existing units and 35% for new units -- are reasonable.

EPA has also requested comment on whether it should revisit these efficiency factors periodically. UARG does not believe that the efficiency factors should be revisited. Coal-fired power plants are designed to maximize energy recovery. The basic design of coal-fired boilers has changed little over the last several decades. Revisiting efficiency factors only creates regulatory complications with no commensurate benefit.

¹³¹ See Lowell L. Smith, "Input and Output-Based Mercury Limits," (Apr. 19, 2004) (Attachment 9).

¹³² See 40 C.F.R. § 60.44a(d)(1).

measurements devices must be installed on all the pieces of electrical equipment used to operate the boiler, and (2) methods are needed to apportion electric usage when facilities have more than one boiler and share common plant equipment. For all these reasons, gross energy output is a more accurate measurement and should be used for compliance where EPA has specified an output-based limit.

E. Monitoring and Compliance Issues

The following sections describe UARG's comments on, and concerns regarding, the emissions monitoring and compliance-related provisions in proposed Subpart UUUUU (the proposed mercury MACT).¹³³ As described below, this proposal has numerous technical and implementation problems, and inconsistencies that would need to be addressed prior to finalization. Although UARG has attempted to describe as many of these as possible either in the text of these comments or in the attached RMB Technical Comments of (Attachment 6), they are too numerous for UARG to describe and address every one. UARG believes that if EPA adopts a MACT approach, EPA will have significant work to do in finalizing this proposal.

1. Use of 12-Month Rolling Average

EPA's proposed format for the mercury standards uses a 12-month rolling average to determine compliance.¹³⁴ EPA considers use of a long-term averaging period to be appropriate because mercury is not an acute health hazard in the context of emissions from utility units, but a

¹³³ Most of the monitoring and compliance related issues associated with EPA's proposed MACT also generally apply to EPA's alternative proposal to regulate under CAA § 111 through revisions to the NSPS at 40 C.F.R. Part 60, Subpart Da for new units and proposed Subpart GGGG guidelines for existing units. The proposed Subparts Da and GGGG utilize much of the same language. Accordingly, many of these Subpart UUUUU comments also apply to the NSPS proposal. Issues that are specific to Subparts Da and GGGG are addressed in Section VI.C.5.

¹³⁴ Proposed 40 C.F.R. § 63.9990(a).

bioaccumulative HAP.¹³⁵ UARG agrees. EPA considered several time periods, including 12-month rolling, quarterly, and yearly.¹³⁶ Because electric utility units already monitor fuel use on a monthly basis for reporting to DOE, EPA proposes use of a 12-month rolling average. Under the proposed rule, sources would calculate compliance each month as the arithmetic average of the most recent 12 monthly averages.¹³⁷

UARG agrees with EPA's decision to base compliance on a 12-month period and generally supports EPA's decision to require calculation of a new average each month. Use of the longer averaging period (*e.g.*, 12 months rather than quarterly) helps to ensure that compliance results will not be skewed by unit outages. And, requiring calculation of a new 12-month average each month allows EPA and the public to determine a source's compliance on a timelier basis than an annual average.

Although UARG supports use of the rolling average of 12 months, UARG has some concerns regarding implementation of the requirement to base the compliance determination on the average of 12 monthly averages, rather than averaging all valid data over the rolling 12-month period with equal weight. Use of the monthly average might simplify the compliance calculations, but it also could result in invalidation of significant amounts of mercury data under the proposed data collection requirements in § 63.10008(d)(4) and would treat each month with equal weight regardless of the amount of data collected. Those concerns are discussed in more detail below. Accordingly, if EPA goes forward with the MACT approach, UARG requests that

¹³⁵ 69 Fed. Reg. at 4668.

¹³⁶ *Id.*

¹³⁷ *See, e.g.*, Proposed C.F.R. §§ 63.10009(d)(2)(i) (calculate mercury “over a month”), 63.10008(d)(4) (substituting a “monthly emissions rate”).

EPA reconsider whether the use of monthly averages (rather than the average of all valid data over the rolling 12-month period) is the best method for calculating compliance.

2. Standards for Blended Coal Units and Supplementary Fuels

UARG supports EPA's decision to utilize a blended emissions limit rather than attempt to establish a separate subcategory for blended fuel units (*see* discussion above), or to classify a unit based on the predominant coal it combusts.¹³⁸ Under EPA's proposal, blended fuel units would establish a unit-specific weighted mercury emissions limit based on the proportion of energy output in British thermal units ("Btu") contributed by each coal rank actually combusted during the applicable 12-month period and the emissions limits for those ranks.¹³⁹ UARG supports this approach as the most equitable of the considered alternatives. UARG, however, has some suggestions for clarification of the regulatory language and equations used to implement the approach.

First, UARG finds confusing EPA's use of the term "monthly" limit in § 63.9990(a)(5). Although a new limit is determined at the end of each month, the calculated limit is based on data from the entire compliance period. As a result, the provision should be revised to make clear that the limit is a "12-month limit" that is calculated on a "monthly basis." With respect to the monthly calculations, the description of the compliance calculations in subsections (5)(i) and (5)(ii) should be revised to make clear that the actual "unit emissions rate based on the total [mercury] loading [] and the total Btu or megawatt hours" also is based on 12 monthly averages that are averaged together, and that the monthly averages are determined using the procedures in § 63.10009. If compliance for the 12-month period was calculated each month by determining a

¹³⁸ 69 Fed. Reg. at 4674.

¹³⁹ Proposed 40 C.F.R. § 63.9990(a)(5).

rate based simply on total mercury and Btu or MWh, without using monthly averages, the proposed data collection and missing data provisions in § 63.10008(d)(4) would not apply as EPA intended. (As noted elsewhere, UARG believes EPA should more fully consider whether the use of monthly averages is the best approach.)

Second, although the proposed blended unit emissions limit and compliance calculations are based on fuel use, the rule is silent regarding the type of fuel measurements and sampling that can be used to determine the Btu output contributed by each coal type. Because utility units are already required to monitor their fuel use for a variety of purposes, no additional requirements need be specified. However, EPA should make clear that sources can use procedures already in place at the source for recording fuel type and monitoring fuel consumption.

Third, EPA's preamble makes clear that EPA did not intend the contribution of non-regulated, supplementary fuels to be included in a blended emissions limit (*e.g.*, emissions limit for unit combusting 40 percent bituminous, 40 percent subbituminous, and 20 percent petroleum coke, would be calculated based on a 50/50 ratio of bituminous and subbituminous).¹⁴⁰ The heat input or electricity output from the non-regulated supplementary fuel is only included in the calculation of compliance with the limit. UARG agrees with that proposal. Although EPA's preamble references a § 63.9990(a)(6), there is no such section. Instead, EPA's proposal includes § 63.9990(a)(5)(ii), which refers back to the same equation used for units that do not combust any non-regulated, supplementary fuel. As drafted, Equation 1 is not clear with respect to its treatment of non-regulated fuel. UARG requests that EPA either revise the existing equation to explicitly state that "HH_i" does not include any Btus or MWhs from non-regulated, supplementary fuel, or provide language in § 63.9990(a)(5)(ii) to accomplish the same result.

¹⁴⁰ 69 Fed. Reg. at 4674-75.

EPA also should clarify that §§ 63.9990(a)(1), (2), (3), and (4) apply to units combusting only the specified regulated fuel, or that regulated fuel in combination with one or more non-regulated, supplementary fuels.

Finally, UARG suggests that EPA revise Equation 1 in § 63.9990 to define the terms “production period” and “ H_i ” (both of which are used in the definition of “ HH_i ”), and to change “MMBtu” to “TBtu.”

3. Compliance Option for Multiple Units

UARG supports EPA’s proposal to allow emissions averaging as a compliance option for two or more coal-fired units, including blended coal units, that are located at a single contiguous plant.¹⁴¹ As EPA explained, the provision will provide operational flexibility while ensuring that required reductions are achieved.¹⁴² However, UARG suggests the following clarifications to provide for smooth implementation of averaging plans.

First, one situation under which sources might wish to utilize averaging is where two or more units utilize a common stack. Common stack monitoring is allowed under the general provisions as long as the “monitoring is sufficient to demonstrate compliance with the relevant standard.”¹⁴³ It is implicit in EPA’s statement that “units that share a common control device are inherently averaged by the standard compliance calculations provided in § 63.10009,” that averaging of units using a common stack (including those with common control devices) is

¹⁴¹ Proposed 40 C.F.R. § 63.9992.

¹⁴² 69 Fed. Reg. at 4682.

¹⁴³ 40 C.F.R. § 63.8(b)(2)(i). UARG notes that EPA’s description of § 63.8(b)(2) in Table 4 (69 Fed. Reg. 4733), as requiring installation of a monitoring system on “each effluent before it is combined,” is inconsistent with the rule and should be corrected.

expected.¹⁴⁴ However, the proposed rules do not make clear under what provision such units should report and whether EPA expects sources to submit averaging plans for such units. EPA should revise the rule to address that point.

Second, under § 63.9992(c) an emissions averaging plan that includes the calculated mercury limit for the averaging group must be included in the Title V operating permit and revised whenever there is a change in the units or the limit. This requirement could present a significant implementation problem for averaging plans (particularly those that include blended-fuel units), because the limit cannot be established until after the compliance period, and the limit would change each month with the actual data. A requirement that the source's Title V permit be modified monthly to incorporate a new averaging plan would be completely unworkable. At a minimum, EPA should revise the provision to affirmatively determine under 40 C.F.R. § 70.6(d)(1)(vi) that such a revision can be made for the current 12-month period at the close of the compliance period and that the revision would be an "administrative permit amendment" that could be implemented upon submittal of the newly calculated limit to the permitting authority. However, because even administrative permit amendments require state approval, EPA should also consider alternative means of implementing an averaging plan that would not require monthly revision of the permit (*e.g.*, consider an approach like that under Part 76 for NO_x averaging plans).

Finally, similar to the comments on the Equation 1 for blended fuel units, Equation 1 in § 63.9992 should make clear that the term "volume of production" is "heat input to, or electricity output from, the emissions source" and should change "MMBtu" to "TBtu."

¹⁴⁴ 69 Fed. Reg. at 4683.

4. EPA's Proposed Compliance Methods

a. General

Under Subpart UUUUU, EPA proposes to allow sources the choice between installing a mercury “continuous emissions monitoring system” (“Hg CEMS”) or monitoring mercury emissions using proposed Method 324.¹⁴⁵ UARG believes that EPA’s decision to allow a choice between the two methods is critical for any mercury regulation, including the proposed MACT, and UARG supports it. As EPA points out, Hg CEMS, which extract combustion gas from the stack and then transfer the gas to an analyzer for analysis, are currently available from several manufacturers.¹⁴⁶ However, as discussed more fully below, none of the currently available Hg CEMS have been used in the field for any significant period of time or been required to comply with proposed Performance Specification 12A. Moreover, what data exist regarding the performance of available Hg CEMS show that the technology currently has significant difficulty meeting the proposed certification, quality assurance/quality control, and data collection requirements.

Although the mercury analyzers are relatively simple devices, they are only capable of measuring elemental mercury and, in order to measure total nonparticulate mercury, the monitoring system must *convert* ionic mercury compounds in the gas stream to elemental mercury.¹⁴⁷ The technology for that conversion is not well developed. Hg CEMS are also very costly, with capital costs alone currently estimated by EPA to range from \$95,000 to \$135,000, and \$45,000 to \$65,000 in annual operation and maintenance depending on the manufacturer and

¹⁴⁵ Proposed 40 C.F.R. § 63.10008(c) and (e).

¹⁴⁶ 69 Fed. Reg. at 4680.

¹⁴⁷ See Docket No. OAR-2002-0056-24 at 1-4 to 1-6.

model.¹⁴⁸ Although UARG does not have sufficient experience with Hg CEMS to confirm EPA's estimates of ongoing operating expenses, UARG is sure that will be much higher than other CEMS as a result of difficulties with the converters. The technology could improve before utilities are required to monitor compliance, but there is no guarantee. As a result, if Hg CEMS were the only option, utilities might be left without a reliable or cost-effective method for establishing compliance.

Proposed Method 324 also operates by extracting combustion gas from the stack for analysis on a continuous basis. However, rather than immediately running the gas sample through an analyzer, Method 324 runs the sample through a "sorbent trap" containing two beds of carbon that collect the mercury for subsequent analysis in a laboratory. Thus, although Method 324 is capable of providing continuous data on stack emissions, the data are not reported on a "real-time" basis. Unlike the Hg CEMS, however, the Method 324 trap collects both ionic and elemental mercury. As a result, no converter is needed. The capital cost for a gas metering system and mercury trapping medium is estimated by EPA to be approximately \$18,000 -- much lower than Hg CEMS. However, EPA estimates that the annual costs for trap replacement and laboratory analysis will range from \$65,000 to \$125,000 annually depending upon the final quality assurance/quality control ("QA/QC") requirements and the frequency of the trap replacement.¹⁴⁹

EPA also considered use of periodic manual stack tests -- either Ontario-Hydro (ASTM Method D6784-02) or EPA Method 29 -- as a compliance method. However, EPA rejected the stack testing option (which EPA estimated would cost \$17,000 per test) as too costly when

¹⁴⁸ 69 Fed. Reg. at 4680.

¹⁴⁹ *Id.*

performing an adequate number of tests.¹⁵⁰ UARG agrees with that determination. Stack testing would not be cost-effective in obtaining a long-term average emission rate, except perhaps at low-emitting units, where emissions variability and total mercury mass is not a significant concern for compliance. EPA's rejection of stack testing also eliminated the need to consider additional parameter monitoring requirements, since those are not necessary when mercury data are collected on a continuous basis.

Recognizing that both proposed methods -- Hg CEMS and Method 324 -- provide the data "necessary to determine compliance with the proposed Mercury emissions limit," EPA has correctly determined that sources should not be restricted in their choice of methods.¹⁵¹ EPA also is correct that selection of the best method for a particular source will depend on site-specific conditions and owner/operator preferences. But, EPA failed to consider the possibility that a source might want to utilize a combination of methods for some period of time either to increase data availability or to determine which performs best at the source. Although UARG does not believe that EPA can require use of redundant systems, there is no reason to prohibit a source from installing both. Given concerns about the reliability of Hg CEMS and the fact that the primary cost in Method 324 is in the analysis of traps, UARG could envision a source installing one method as the primary monitoring system and the other method as a backup system. If the Hg CEMS was the backup system, the monitor would only need to be calibrated on those days when data from the monitor were reported. Similarly, if Method 324 was the backup system, the traps would only be used and analyzed if the Hg CEMS was unavailable. Accordingly, UARG suggests that this *option*, which is provided under the March 16, 2004 cap-

¹⁵⁰ *Id.* at 4681.

¹⁵¹ *Id.*

and-trade proposal (*see* comments below), be included in the proposed MACT as well. Optional use of backup monitoring systems is consistent with the general provisions in § 63.8(a)(3).

Given the significant costs of the proposed monitoring options, UARG (like EPA) is concerned that the monitoring costs for units with low mercury emissions rates will be disproportionate to the costs of compliance with the MACT emissions limitations.¹⁵² Some data obtained during testing of Method 324 suggest that mercury emissions at utility units using wet scrubbers will be extremely low. Accordingly, UARG agrees that EPA should adopt reduced monitoring frequencies and lower cost monitoring requirements for very low-emitting units. Where a source can demonstrate through a combination of testing (*e.g.*, stack testing or periodic Method 324 analysis) and operating data that it is a very low-emitting unit, either because of its (1) size, (2) operating time, or (3) control device operation, that source should be allowed to rely on those factors, rather than continuous mercury measurements, to confirm its future low emissions.

In order to evaluate EPA's proposed compliance methods more fully, UARG asked its technical consultants at RMB to review the proposed performance specifications and test method, as well as the data EPA relied upon in their development. RMB's specific comments are set out in the attached Technical Comments (Attachment 6). UARG agrees with and adopts RMB's comments, some of which are summarized below.¹⁵³

¹⁵² *Id.*

¹⁵³ These comments on EPA's Mercury CEMS Program, EPA's proposed Performance Specification 12A, and proposed Method 324 apply to use of Hg CEMS and the sorbent trap monitoring system under EPA's proposed cap-and-trade program as well.

b. Performance Specification 12A

Under EPA's proposal, any Hg CEMS used to determine compliance would have to meet proposed Performance Specification 12A ("PS 12A").¹⁵⁴ UARG has the following comments on the proposed specification.

One of UARG's primary concerns with the proposed specification is the uncertainty surrounding the ability of commercially available Hg CEMS to meet the proposed performance criteria. Although UARG understands, and agrees, that any Hg CEMS used to determine compliance must be subject to accuracy standards to ensure that the reported compliance determinations are correct within some acceptable margin, UARG is also aware that the burden of meeting those accuracy standards will fall (not on EPA or the CEMS manufacturers) but on its members. Unfortunately, as the results of EPA's Mercury CEMS Program illustrate, it is not yet clear that any of the available Hg CEMS could meet all the proposed standards, let alone do so over any significant period of time.¹⁵⁵ Although UARG is not recommending that EPA loosen the proposed standards, UARG does request that EPA ensure that the specifications are structured to include necessary alternatives, like low-emitter standards, and that EPA's other rules (like those addressing missing data) take into account the uncertainty associated with meeting PS 12A. The following summarizes UARG's more specific comments, including some RMB's Technical Comments.

Section 1.2.1 requires that Hg CEMS measure mercury in micrograms per cubic meter on a dry basis with concentration corrected to 7 percent CO₂ and requires evaluation of the combined performance of the mercury monitor and a diluent. First, the correction should be to 7

¹⁵⁴ Proposed 40 C.F.R. § 63.10008(d)(1) and (2).

¹⁵⁵ RMB Technical Comments, Section 6 (Attachment 6).

percent O₂ (not CO₂) as reflected in Equation 12A-3. In addition, EPA should allow for evaluation of the mercury monitor without the diluent (in micrograms/m³) and remove the dry basis requirement. Wet basis measurements, which could prove to be superior, should not be precluded. Alternatively, the monitors could be evaluated in terms of lb/TBtu.¹⁵⁶

With respect to monitor span, § 3.6 requires that span be set at “two times the emission standard.” This presents several problems. First, this requirement is not consistent with the emissions limits in the proposed MACT, which are expressed in terms of lb/TBtu or 10⁻⁶ lb/MWh, whereas Hg CEMS spans are expressed in micrograms. Second, not all regulatory programs will involve specific emissions limits and instead will include specific procedures for selecting a span (or spans). If PS 12A were used under EPA’s cap-and-trade program, for example, § 3.6 would conflict with the span provisions in 40 C.F.R. Part 75 (“Part 75”), making compliance with both impossible. To resolve this conflict, EPA should revise § 3.6 to state that the span should be set in accordance with applicable regulations for the use of the Hg CEMS. A default value of “twice the emission standard” should only apply if there are no such span requirements in the applicable regulations.¹⁵⁷

Section 8.1.1, which proposes to require testing for SO₂ and NO_x stratification at the proposed installation location, is not consistent with other EPA regulations. Although UARG agrees that mercury will not be stratified if either SO₂ or NO_x are not stratified, regulations addressing CEMS for those pollutants do not require stratification testing prior to location of the monitor. Instead, those regulations deem the location suitable as long as the relative accuracy

¹⁵⁶ *See id.* at 6-5.

¹⁵⁷ *See id.*

test audit (“RATA”) is passed.¹⁵⁸ EPA has not provided any rationale for using different location criteria in PS 12A, nor does UARG believe there is one. As in EPA’s other rules, stratification testing should only be required if the source uses a wet control device (or is otherwise expected to have stratification) *and* exercises the option to use a short measurement line or a single measurement point during RATA testing. The section should be revised accordingly.¹⁵⁹

In § 8.2, EPA proposes to *require* sources to locate the reference method at a point or points “as close as possible” to the Hg CEMS sampling point. This requirement is a sharp departure from other performance specifications.¹⁶⁰ UARG suspects that EPA chose this procedure to minimize sampling error associated with the reference method and make it easier for the Hg CEMS to pass the relative accuracy (“RA”) specification, since available data from EPA’s Mercury CEMS Program show that the CEMS have difficulty passing even with a single point measurement. Although UARG agrees that EPA should provide single point sampling as an *option*, imposing this criterion as a *requirement* is inconsistent with other rules, such as Part 75, under which EPA is proposing to require compliance with PS 12A. Again, EPA should limit this provision to an *option*, as it is provided under other rules.¹⁶¹

Section 8.3 establishes measurement error tests of the Hg CEMS using National Institute of Standards and Technology (“NIST”) traceable concentrations of elemental mercury (“Hg⁰”) and mercuric chloride (“HgCl₂”). EPA’s reliance on NIST traceable gases in the proposed measurement error test in § 8.3 poses several problems. First, it is not certain that such gases are

¹⁵⁸ See, e.g., Part 75, Appendix A, § 1.1; Part 60, Appendix B, PS 2, § 8.1.1.

¹⁵⁹ See RMB Technical Comments, at 6-5, 6-6 (Attachment 6).

¹⁶⁰ See, e.g., Part 60, Appendix B, PS 2, § 8.1.3.2.

¹⁶¹ See RMB Technical Comments, at 6-6 (Attachment 6).

even in existence, let alone commercially available. Although UARG has identified one vendor that is close to offering Hg⁰ calibration gas, that same vendor has concluded that it is impossible to make a calibration gas cylinder containing HgCl₂ because the chemical is solid at room temperature. The one device -- the Hovacal -- that has the potential of delivering “known concentrations of HgCl₂,” has not been tested for precision or accuracy, let alone NIST traceability. UARG believes that this is a serious technical problem with converter equipped Hg CEMS that will need to be overcome.¹⁶²

The measurement error testing requirements are also problematic because there are no data to establish that the proposed standards can be met. All of the data in EPA’s studies pertain to Hg CEMS that were calibrated with a liquid solution every 6-12 months or were factory calibrated. Moreover, available gases could have significant variability that could interfere with compliance with the specifications. In short, EPA is proposing to require Hg CEMS to follow a procedure and meet specifications for which the Agency has neither any experience nor data to support. Although UARG agrees that calibration standards are a necessary requirement for ensuring CEMS accuracy and that the Hg CEMS converters are especially in need of calibration, the uncertainties associated with these requirements must be taken in to account in other rules that rely on PS 12A certification, such as the missing data rules.¹⁶³

Section 8.6 requires that relative accuracy tests be conducted with paired trains or duplicate sampling systems and that data pairs that fail the proposed relative standard deviation (“RSD”) test be discarded. Use of paired trains will increase the cost of testing and result in the discarding of more sample runs. Unfortunately, because sample run results will not be available

¹⁶² *See id.*

¹⁶³ *Id.* at 6-6, 6-7.

until a significant time after testing (2-4 weeks), it is not possible to determine how much data should be collected to ensure the minimum 9 runs remain after discarding those runs. As a result, sources that fail to collect enough runs the first time could be faced with months of delay before RA results are available (and if the test is failed, potentially months of missing data). Each time a paired train is discarded because of a potentially bad measurement, a potentially good measurement is also discarded. If EPA believes that the precision and accuracy of the reference method is inadequate, EPA should raise the RA specification to account for that error or develop an outlier test that will eliminate obviously bad data. In fact, the proposed ≤ 10 percent RSD between runs already subsumes a significant portion of the proposed ≤ 20 percent RA standard.¹⁶⁴

If the final PS 12A includes the paired train requirement, EPA must revise the rule to explain how those results are to be used. Neither § 8.6, nor the calculation provisions in § 12.0, detail how paired train results are to be handled in the calculation of RA. UARG assumes that paired train results that pass the outlier RSD test in § 8.6 are supposed to be averaged to obtain a single run reference method value, but that is not stated anywhere in PS 12A. EPA should review the specification to ensure that all such details are addressed.¹⁶⁵

Finally, § 13.0 should be revised to include low-emitter alternative standards for calibration and relative accuracy, similar to those in the March 16, 2004 proposed Part 75 revisions under the cap-and-trade alternative. As proposed, PS 12A would apply the same calibration standards to all units regardless of their emissions level, and would apply an alternative RA standard based on 10 percent of the applicable standard. Experience under Part

¹⁶⁴ *See id.* at 6-7, 6-8, 6-9.

¹⁶⁵ *Id.* at 6-7.

75 has demonstrated that where emissions are very low, alternative calibration standards expressed in absolute terms (rather than as a percent of span) are necessary. Moreover, use of criteria that are not expressed in terms of applicable emission standards are necessary for application to sources where there either is no emissions limit (*e.g.*, a trading program) or where multiple limits might apply. Because some sources will have very low mercury emissions, low-emitter standards that are reasonable and consistent with other rules are important, and should be included. Absent some data showing that the low-emitter standards in proposed Part 75, Appendix A, §§ 3.1 and 3.3.8, are not appropriate, UARG requests that EPA include those standards in PS 12A or include a provision stating that low-emitter standards in other applicable regulations may be used in lieu of the standards in PS 12A.

c. Method 324

Under EPA's proposal, sources that choose to use the longer-term sorbent trap monitoring method rather than a Hg CEMS would be required to follow Method 324.¹⁶⁶ UARG commends EPA for recognizing the legitimacy of and need for this method. UARG has the following comments on the proposed procedures in Method 324.

As an initial matter, UARG believes that the Method could be improved by providing additional details regarding what is required for the sorbent trap. For example, § 6.1.1 refers to sorbent traps as the collection media, but does not specify the contents of the traps, how that material is prepared, or the differences between the amount of sorbent material in the two sizes described in Table 324-1. UARG believes that the Method should be revised to include the information referred to in RMB's comments.¹⁶⁷ Although such information may not be

¹⁶⁶ Proposed 40 C.F.R. § 63.10008(e).

¹⁶⁷ See RMB Technical Comments, at 6-13, 6-14 (Attachment 6).

important to the current manufacturers of such traps, it will be important for further development of the market.

Method 324 requires use of paired sorbent traps whenever the method is used to collect data to demonstrate compliance.¹⁶⁸ Although use of paired traps could be beneficial if one trap could serve as a backup in the case of an equipment failure, UARG is concerned that the requirement for analysis of paired traps will simply create problems, similar to those discussed above with respect to PS 12A, with respect to treatment of disparate results. It also will significantly increase the cost of the method. Accordingly, UARG requests that EPA reconsider whether collection and/or analysis of paired trap samples should be required.¹⁶⁹

One important aspect of the Method 324 measurement is avoiding condensation in the sorbent trap by heating the sampling probe in those conditions where the gas stream may fall below the condensation point. Section 6.1.2 requires use of a heated sampling probe for effluents below 200°F as measured with a thermocouple. UARG suggests the lower boundary of the range be increased to 250°F to ensure that no water droplets form in the sorbent trap.¹⁷⁰

Another important aspect of the measurement is determination of the sample volume. Section 6.1.6 requires that the dry gas meter (“DGM”) be calibrated using the procedures in Method 5 of Appendix A of 40 C.F.R. Part 60. UARG believes the reference should be changed to the procedures in Method 6 of Appendix A of 40 C.F.R. Part 60. The Method 5 procedures are designed to calibrate a DGM measuring a nominal flow rate of 21.2 liters per minute (“lpm”), whereas the Method 6 procedures are designed specifically for lower flow rates. The typical

¹⁶⁸ Proposed 40 C.F.R. § 6.1.

¹⁶⁹ See RMB Technical Comments, at 6-13 (Attachment 6).

¹⁷⁰ See *id.* at 6-14.

Method 6 flow rate is 2.0 lpm, which is more comparable to the 0.2 to 0.6 lpm flow rates listed in proposed Method 324.¹⁷¹

Similar to proposed PS 12A, § 8.1.1 proposes to require testing for SO₂ and NO_x stratification at the proposed installation location. As explained above, this requirement is not consistent with other EPA regulations and should be revised to deem the location suitable as long as the RATA is passed.¹⁷² As in EPA's other rules, stratification testing should only be required if the source uses a wet control device (or is otherwise expected to have stratification) *and* exercises the option to use the short measurement line or a single measurement point during RATA testing.¹⁷³

The proposed method appropriately requires leak checks of the sampling line with and without the sorbent trap in place.¹⁷⁴ The checks are performed using a rotameter. UARG is concerned that with a nominal flow rate of 0.4 lpm (*see* Table 324-1), 2 percent of that flow rate (which is the maximum leakage allowed under the proposal) may be too low to be accurately read on a standard rotameter. Accordingly, UARG suggests that EPA consider revising the Method to quantify the leak rate based on readings from the DGM over a period of at least 1-minute, as described in RMB's comments.¹⁷⁵

Proposed Method 324 provides for both constant-flow rate sampling (to be used for samples less than 12 hours) and proportional flow rate sampling (to be used for all samples

¹⁷¹ *See id.*

¹⁷² *See, e.g.,* Part 75, Appendix A, § 1.1; Part 60, Appendix B, PS 2, § 8.1.1.

¹⁷³ *Id.*

¹⁷⁴ Proposed §§ 8.1.4, 8.1.6 and 8.2.6.

¹⁷⁵ *See* RMB Technical Comments, at 6-14 (Attachment 6).

greater than 12 hours). UARG has several comments on these provisions. First, UARG requests that EPA revise § 8.2.4 to make clear that proportional sampling can be used for any period (including those less than 12 hours). There is no reason to make sources revert to constant-flow rate sampling if they have a proportional sampling apparatus in place. Second, UARG is concerned that the constant-flow sampling procedures in § 8.2.3 are too complex and request that EPA consider the revisions outlined in RMB's comments.¹⁷⁶ Third, UARG points out that the procedures in § 8.2.4 for proportional flow are inconsistent with the procedures in the proposed Part 75 revisions for a cap-and-trade program. As discussed below, UARG does not believe that the Part 75 procedures are reasonable. Instead, UARG prefers the procedures in proposed Method 324, which are capable of being automated.¹⁷⁷

Section 8.2.5 requires that unit-operating data be collected during the test period, including stack flow rate and oxygen concentration at the flue gas test location. UARG believes the Method should allow either carbon dioxide or oxygen concentration data. Most utility units already measure CO₂.¹⁷⁸

Table 324-2 sets out the quality control requirements for samples. UARG is concerned that some of these requirements are excessive or not sufficiently explained or studied. For example, the requirement for laboratory blanks could be excessive for large trap lots. And, without more data, it is not possible to determine whether the paired train criterion (which is not set out anywhere else in the rule) is subject to the same problems as PS 12A, § 8.6.6 (*see*

¹⁷⁶ *See id.*, at 6-15.

¹⁷⁷ *See id.*

¹⁷⁸ *See id.*

comments above). Finally, the field spiking requirement is not sufficiently explained. These problems are explained more fully in RMB's comments.¹⁷⁹

One of the primary components of quality control will be documenting a chain of custody for the sorbent sample. For example, the Method requires that laboratory and field blanks be analyzed using traps from the same lot as those used in sampling, but does not provide any procedures for documenting the lot numbers. Although utilities are capable of designing their own procedures for documentation, UARG believes that it makes more sense for those requirements to be contained in the Method. Accordingly, EPA should revise Method 324 to require that each trap be inscribed or otherwise permanently marked with the trap's lot number and an individual serial number for that trap, and that a certification sheet accompany each trap. Additional details for such a system are provided in RMB's comments.¹⁸⁰

Finally, several provisions, including §§ 13 and 14, purport to contain requirements for calculations and data analysis. These sections are inadequate. These sections should contain all of the equations and calculations needed to conduct the Method and arrive at mercury emissions values that are either in the units of applicable standards or that can be converted to those units. Procedures for incorporating blank determinations should also be included.¹⁸¹

d. Conclusions

UARG believes that proposed PS 12A and Method 324 are reasonable first steps in the process of defining requirements for relatively new technologies in emissions measurement that do not have a significant body of field data for support. With consideration of the above

¹⁷⁹ See *id.* at 6-15, 6-16.

¹⁸⁰ See *id.* at 6-13.

¹⁸¹ See *id.* at 6-16.

comments and a willingness to revise each procedure as data become available, UARG believes that the procedures can be used successfully in the proposed regulatory contexts. UARG suggests that EPA utilize the one-year extension for compliance with the MACT emissions limitations (discussed below) to provide an additional year in which utilities could implement a monitoring program prior to the start of the first compliance period (similar to the Acid Rain Program designed by Congress, which provided a full year of monitoring and reporting for Phase I units and 5 years for Phase II units), and that EPA commit in the final rule to evaluate the results of that monitoring to determine if revisions are appropriate.

5. Deadlines for Monitoring, Testing, and Compliance¹⁸²

UARG is concerned that the deadlines for monitoring, testing, and compliance provided in several sections of Subpart UUUUU are internally inconsistent and, if taken literally, would be impossible to meet. The following describes some of the problems with these provisions.

Under §§ 63.9983(a) and 63.10008(d), new units must (1) install and operate monitors, and (2) comply with the “emissions limitations and work practice standards” *upon the later of publication of the final rule, or startup*. Under § 63.10005, sources then have 180 days after the date for compliance with “emissions limitations and work practice standards” in § 63.9983, to complete all performance tests, selection of operating parameters, and monitoring equipment performance evaluations.

Under §§ 63.9983(b) and 63.10008(d), existing units must (1) install and operate monitors, and (2) comply with “emissions limitations” *by 3 years after the final rule is published*. Section 63.10005 states that performance tests, operating limits and monitoring

¹⁸² The comments in this section are applicable to all units subject to the proposed Subpart UUUUU, including oil-fired units.

equipment performance evaluations also must be conducted by the compliance date in § 63.9983 (*i.e.*, 3 years from publication of the final rule), but done so according to the applicable provisions in § 63.7(a)(2), which (unlike § 63.9983) allows 180 days from the compliance date for performance testing (*i.e.*, 3 years and 180 days after publication).¹⁸³

For both new units and existing units, however, § 63.10009(d) states that “compliance monitoring” must begin on the “effective date of this subpart.”

These provisions are confusing and conflicting. For new units, the requirement to “comply” with “emissions limitations and work practice standards” on the date of publication of the final rule and 180 days *before* the deadline for performance testing, selection of operating parameters, and monitoring equipment evaluations in § 63.10005 makes no sense. Sources cannot be expected to comply without a performance test or monitoring system in place to establish compliance. For existing units, the rules also are in conflict as to whether an additional 180 days is allowed for performance testing, selection of operating parameters, and monitoring equipment performance evaluations. If the additional 180 days is provided, the deadline for compliance must also be extended. Moreover, for mercury, these provisions also fail to recognize that sources cannot establish compliance with the mercury emissions limitation until 12 months after the monitoring system evaluation has been completed and the required 12 months of compliance data have been collected.

For both new and existing units, the requirement to begin “compliance monitoring” on the effective date of the rule, also makes no sense. It conflicts with the provisions in § 63.9983

¹⁸³ UARG notes that Table 4 (69 Fed. Reg. at 4731) provides descriptions of § 63.7(a)(2)(i)-(viii) that are inconsistent with those provisions as currently promulgated. If EPA intends to make changes to those provisions, EPA must issue a proposal. In the meantime, EPA should correct the descriptions.

establishing “publication” (not the effective date) as the triggering point, ignores the fact that some new units may not even have started-up, and ignores the additional 180 days that are supposed to be provided under § 63.10005.

EPA should follow the model in Part 75 and establish a deadline for applicability of the subpart and then a single deadline for installation, operation, and evaluation of monitoring systems and for performance testing and selection of operating parameters. For new units, the deadline for applicability of the rule would be the later of publication or unit startup. For existing units, the applicability date would be 3 years after the date of publication of the rule. The deadline for installation, operation, and certification of monitoring systems and for performance testing and selection of operating parameters (*i.e.*, the point when “compliance monitoring” is begun) would be 180 days later. The deadlines for establishing compliance with the mercury standard should be the end of the initial 12-month compliance period. At the time of the demonstration of compliance for the initial 12-month period, sources would be deemed to be in compliance for the prior 12 months. As a result, they would at that time have met the statutory deadline for compliance. The deadlines for compliance with the nickel standard should be the same as the deadline for compliance testing and establishment of operating parameters -- *i.e.*, 180 days after the applicability date.

6. Quality Assurance/Quality Control

UARG is concerned that the proposed provisions addressing QA/QC are not sufficiently clear regarding the procedures to be used to conduct the required tests and quality assure data. Section 63.10008(g) requires quarterly accuracy determinations and daily calibrations for Hg CEMS, and an annual RATA for sorbent trap monitoring systems, all of which are to be performed “in accordance with” Procedure 1 of Part 60, App. F. Procedure 1 generally sets out the requirements for such tests, but relies on individual performance specifications (*e.g.*, PS 12A)

for certain details. Although proposed PS 12A has been designed to include many of those details, Method 324 has not. Because Method 324 is a test method (and not a performance specification), it does not include any RATA procedures or a RATA standard. Indeed, those procedures should not be included in Method 324.

Accordingly, EPA needs to correct this deficiency by providing a reference in Subpart UUUUU to the RATA procedures and standards for regular and low-emitting units that will be applied when conducting RATAs on a sorbent trap monitoring system meeting Method 324. Specification of low-emitting standards, like those in the proposed revisions to Part 75 for a cap-and-trade system, are important, since data suggest that many units using the method will have very low emissions. EPA should also review proposed PS 12A to ensure that all of the necessary procedures and standards are provided.

Alternatively, because Method 324 is a test method itself, UARG believes that EPA could justify a rule that did not require a RATA for validation of the sorbent trap system. UARG is not aware of any other instance where EPA has required that an EPA test method be compared to another test method using RATA procedures prior to use to determine compliance. Use of the RATA in this case is unusual given the mixed performance of the Ontario-Hydro method that would be used for the RA test.¹⁸⁴ Because Method 324 is a new method that has not been employed in practice, UARG is not objecting to an annual RATA requirement. Such testing in the early years of the program could provide valuable information for improvement of both methods. However, UARG would object to any more frequent testing. Method 324 already provides significant QA/QC in its sampling and analysis procedures and additional RATA testing would be unwarranted.

¹⁸⁴ See RMB Technical Comments, Section 6 (Attachment 6).

Finally, UARG is concerned that EPA has overlooked a potential problem with the requirement to subject Hg CEMS and Method 324 to periodic RATAs and/or other audits that rely on comparison to EPA test methods for mercury (including Method 29 and the Ontario-Hydro method). Unlike the instrumental reference methods routinely used to quality assure SO₂ and NO_x CEMS, the available mercury test methods can take days to complete and weeks for the return of test results from the laboratory. Under the current general provisions, a monitor that fails a RATA would be deemed out-of-control beginning with the hour that the required test was conducted until the hour that the test is successfully passed.¹⁸⁵ This construct could lead to significant implementation problems with respect to missing data and requirements to calculate and report data.

If a source does not know until weeks after a RATA is completed whether the test was passed, the source has no means of minimizing missing data associated with a failed test. Similarly, once it is clear that a test has been failed, the source must schedule and perform a new test and wait for results before determining whether the monitor is back in control and the data are valid. Under these procedures, monitoring systems that fail a RATA will have significant amounts of missing data due simply to the delay in obtaining testing results.¹⁸⁶ Until a method is developed that will allow for onsite results of mercury RATA testing, EPA must provide special rules to avoid these unavoidable implementation problems.

7. Data Availability and Missing Data

Proposed § 63.10008(d)(4) establishes data collection requirements for Hg CEMS. Under that rule, an Hg CEMS must collect 18 hours of data in each 24-hour period for a

¹⁸⁵ 40 C.F.R. § 63.8(c)(7)(ii).

¹⁸⁶ See RMB Technical Comments, 6-9, 6-10 (Attachment 6).

“complete day,” and 21 complete days in a calendar month for “complete month.” The first time a complete month of data is not collected in a 12-month period, data for that month are replaced with the “mean of the individual monthly emission rate values” in the last 12 months. Each additional time a complete month of data is not collected during a 12-month period, the data for that month are replaced with the highest individual monthly emissions rate determined in the last 12 months. The rule does not specify what is to be done if the Hg CEMS fails to collect enough data in the first month of operation.

This data collection and missing data scheme has several significant flaws. The first flaw is the assumption that these minimum criteria are reasonable requirements for Hg CEMS. There are no data to support the assumption that Hg CEMS will be capable of operating within the specified performance criteria for 18 hours a day for 21 days each month.¹⁸⁷ Sources should not be penalized for failing to meet minimum criteria that may not in fact be achievable. As a result, EPA will need to continue to review this requirement in light of additional data collected between now and the first compliance deadline. As discussed above, EPA also should revise the rules to allow use of Method 324 as a backup for any source that chooses that option, and should allow data from that method to be used to meet the minimum data requirements in lieu of a Hg CEMS.

The second flaw in the rule, even if you assume that the Hg CEMS can meet the minimum criteria, is the failure of the rule to distinguish between unit operating hours and non-operating hours in determining if a day is complete. If the minimum requirement applies regardless of unit operation, sources will be required to try to keep monitors running and quality assured, and to calculate mass mercury, even if the unit is not operating in order to collect

¹⁸⁷ *See id.* at 2-4, Section 6.

enough data for a complete day. That is contrary to § 63.10020(a) (“you must monitor continuously [] at all times that the affected source is operating”). That would also result in months with little operation, and therefore very little actual mercury mass emissions data, being counted in the 12-month rolling average with the same weight as months with significant operation.

If, on the other hand, the source does not collect that data, any day the unit does not operate and most days involving a startup or shutdown are likely to be “incomplete” and not count towards the required 21 days for a complete month. Under the missing data provisions, that approach would mean that valid data would be thrown out simply because there was not enough unit operation in the month. Sources should not be required to operate monitors when they are not operating, and should not be penalized for non-operation. As a result, EPA should give more thought to whether the data collection and missing data provisions associated with the calculation of “monthly” averages is the best approach.¹⁸⁸

For Method 324, the proposal needs to include provisions for data availability and missing data. Because it is not reasonable for EPA to expect 100 percent data capture from any method, EPA must specify at what point sorbent trap data would need to be filled in and what method would be used. EPA might also consider providing alternative minimum data collection and missing data requirements that would to apply simply to mercury data, regardless of the method of collection.

Several other provisions related to minimum data collection and missing data also are incomplete or confusing. For example, § 63.10020(b), which prohibits use of data recorded during “monitoring malfunctions, associated repairs, or required quality assurance or control

¹⁸⁸ *See id.* at 2-4.

activities” in data averages or calculations, fails to include a reference to “out-of-control” periods. Not all out-of-control periods will be tied to clear monitor malfunctions. Accordingly, the section should be revised to include “out-of-control” in the list of periods when data cannot be used and should cite the definition in § 63.8(c)(7). Section 63.10020(b) also states that all data collected during other periods must be used when “assessing the operation of the control device and associated control system.” This provision is confusing as applied to Hg CEMS, and is inconsistent with the provisions in § 63.10008, which requires discarding of valid data that do not meet the minimum collection criteria. If this provision was only intended to apply to “continuous parameter monitoring systems” (“CPMS”) used by oil-fired units, that should be made more clear.

Finally, EPA needs to clarify how periods of startup, shutdown, and malfunction are to be treated in data collection and reporting. The proposed rule appropriately states that deviations that occur during periods of “startup, shutdown, or malfunction” (“SSM”) are “not violations” if the source was operating in accordance with its SSM plan.¹⁸⁹ However, the proposal does not explain whether or how those data would be excluded from the compliance calculation, or how they would be treated with respect to the data collection requirements. Presumably EPA does not mean that any 12-month rolling average in excess of the standard that includes a period covered by an SSM plan is not a violation. On the other hand, data collected during periods of SSM are not representative of normal operations and should not be included in data averages used to determine compliance and missing data substitution procedures. EPA needs to give

¹⁸⁹ Proposed 40 C.F.R. § 63.10021(c).

additional thought to these issues and provide clear instructions in the rule for how such periods would be treated.¹⁹⁰

8. Compliance Calculations

a. General

UARG has a number of concerns about the equations and calculation procedures provided to calculate compliance with the mercury emissions limitations. Some of the equations are incomplete, use terms that are not defined, or are inconsistent in terms of form. For example, none of the equations using Btus or MWh specify how those values are to be measured. EPA should review all equations for accuracy and completeness and revise them accordingly, (*e.g.*, for MWh, specify total gross megawatt hours measured with a wattmeter).

UARG offers the following specific comments. Additional detail and comments are provided in the attached RMB Technical Comments (Attachment 6).

b. Equation 1 for Averaging Groups

Equation 1 for averaging groups in § 63.10009(b) states that it is calculating total mercury emissions “for the 12-month compliance period.” This description is confusing because it is inconsistent with the other compliance provisions in § 63.1009, which calculate compliance for each “month” and then determine the average of the 12 months. If compliance is not calculated for each month, the proposed data collection and missing data provisions in § 63.10008(d)(4) will not be applicable, and EPA would have to make clear that only those hours for which both mercury mass emissions and total volume (“ V_1 ”) are available would be used to calculate an individual unit’s emission rate. If EPA intends calculation of compliance on a

¹⁹⁰ For example, EPA deals with periods of “startup, shutdown, and malfunction” in proposed Subpart Da by specifically excluding those data from the compliance calculation. Proposed 40 C.F.R. § 60.50a(h)(1).

monthly basis for averaging groups, EPA should reference the equations in subsection (d) for those calculations.¹⁹¹

c. Equation 3 for Hg CEMS

Equation 3 in § 63.10009(d)(2)(i), which is used to calculate mass emissions from Hg CEMS, has several problems. First, to make the equation more understandable, UARG recommends that it be converted to a summation equation. The use of the integral form is confusing and inconsistent with the other equations in the subpart. Second, the equation is incomplete because it fails to specify how flow rate is determined. EPA should revise the provision to specify that “volumetric flow rate” is determined using the procedures in either 40 C.F.R. Part 60 or 40 C.F.R. Part 75. EPA could use the language from the existing Subpart Da output-based NO_x limitation as a model.¹⁹² Third, Equation 3 inappropriately assumes that there will be mercury concentration data and flow data for all hours. That would be very unlikely. EPA should revise the equation to make clear that only those hours for which valid mercury concentration data and volumetric flow data are both available are used in the equation. Finally, in Equation 3 as currently drafted, mercury concentration is on a dry basis and volumetric flow is on a wet basis. The two measurements must be on the same basis in order for the equation to work. To convert the wet basis volumetric flow to dry basis, stack moisture must be used. EPA should revise the equation to include the moisture correction.¹⁹³

¹⁹¹ See RMB Technical Comments, at 2-5 (Attachment 6).

¹⁹² See, e.g., Subpart Da § 60.47a(l), (m), (n).

¹⁹³ See RMB Technical Comments, at 2-5 (Attachment 6).

d. Method 324 Calculations

Section 63.10009(d)(3) for calculating mercury mass emissions from Method 324 also has several problems. First, the equation should explain what is meant by the term “emission rate period,” which is not defined. Presumably this is the sampling period over which a single trap is used. Second, like the Hg CEMS equation, the provision should be revised to specify that volumetric flow rate is determined using the procedures in either 40 C.F.R. Part 60 or 40 C.F.R. Part 75¹⁹⁴ and to limit calculations to hours for which there are both mercury and flow values. Third, the provision should be revised to state which of the paired trap results from Method 324 are to be used in the calculation. As described below, UARG objects to EPA’s proposal in Part 75 under the supplemental notice of proposed rulemaking that the higher of the two values should be used. Instead, EPA should use standard procedures for paired trains.¹⁹⁵ Finally, the provision should be revised to explain how the 12-month rolling average is calculated from the mercury mass emissions rate for the “emission rate period.” To calculate a 12-month rolling average consistent with the other provisions for mercury, the source would first calculate a monthly rate and then average the 12 monthly rates. However, no procedures are provided for determining a monthly rate from the Method 324 “emission rate period.” If EPA intends to simply calculate an average of all of the “emission rate periods” in the prior 12 months, EPA needs to specify that and evaluate how that data would be used in the equations for blended fuels or for averaging groups, which are drafted to use monthly averages.

¹⁹⁴ See, e.g., language from Subpart Da § 60.47a(l), (m), (n).

¹⁹⁵ See, RMB Technical Comments, at 5-6 (Attachment 6).

e. Equations 4 and 5 for Hg CEMS and Method 324

As with the other equations, Equations 4 and 5 in § 63.10009(d)(2)(ii) and (iii), which are used to calculate the emission rate from the mass mercury emissions values, inappropriately assume that there will be mercury mass emissions data for all operating hours. The equations should be revised to make clear that the calculation of Total Power (input-based and output-based) are limited to those hours for which there are mercury mass emissions data available.

9. Recordkeeping and Reporting

UARG has identified a number of inconsistencies in the recordkeeping and reporting provisions. First, the preamble indicates that sources will be required to maintain monthly records of types of fuel burned, total fuel usage, and fuel heating value, but these requirements do not appear in the proposed rule.¹⁹⁶ EPA should add a provision for recording those values consistent with existing company practices. Second, § 63.10030(e) states that a “Notification of Compliance Status” must be submitted for each “performance test” or “initial compliance demonstration” as specified in § 63.10007. Section 63.10007, however, only covers performance testing for “oil-fired” units. Initial compliance demonstrations for coal-fired units are addressed in § 63.10009. If EPA intends a “Notification of Compliance Status” to be submitted by coal-fired units following the first 12-month period, a reference to § 63.10009 should be added. If EPA does not intend for coal-fired units to submit that notice, the reference to the “initial compliance demonstration” should be removed or clarified.

Section 63.10007(b) also requires submission of a “Notification of Compliance Status” report containing the “initial or annual compliance demonstration” according to the requirements of § 63.10031(b). Section 63.10031(b), however, addresses the requirements for “semi-annual

¹⁹⁶ See, e.g., 69 Fed. Reg. at 6282.

compliance reports.” The requirements for “Notification of Compliance Status reports” are contained in § 63.10030(e). That fact is also clear from § 63.10009(f), which also requires submission of the “Notification of Initial Compliance Status” report according to § 63.10030(e). EPA should explain the difference between the two reports, review the above provisions for accuracy, and eliminate the duplicate requirements.

Section 63.10030(a) requires compliance with many notices in the general provisions, including the “Notification of Compliance Status” in § 63.9(h). That requirement is confusing given that § 63.10030(e) sets out requirements for “Notification of Compliance Status” that are narrower than those in § 63.9(h) (*e.g.*, § 63.10030(e) only requires compliance with § 63.9(h)(2)(ii)). EPA should review these provisions and address the inconsistencies and overlapping requirements to better explain to sources what is required in each applicable notice or report. Section 63.10030(a) also requires compliance with § 63.6(h)(4) and (5). However, according to Table 4, those provisions, which relate to opacity and visible emissions observations are not applicable. As a result, they should be removed from § 63.10030(a).

Section 63.10009(d)(4) requires reporting of the 12-month rolling average mercury emissions rate in the “first semi-annual compliance report.” If the initial semi-annual report will be submitted before 12 months of data have been collected, as § 63.10031 requires, it is not possible to report a 12-month rolling average. EPA should remove this requirement and clarify how and when results are to be reported (*e.g.*, first in the initial “Notification of Compliance Status” and thereafter in the next semi-annual report).

10. Definitions

UARG also has identified a number of instances where the definitions do not reflect the proposed regulatory provisions. For example, the provisions for regulation of “oil-fired” units

apply to *any* unit combusting oil.¹⁹⁷ Because some coal-fired units combust oil for start-up, the definitions of “coal-fired” and “oil-fired” should be revised to make clear that units that combust both coal and oil are not “oil-fired,” and that any unit regulated as a coal-fired unit is not subject to the “oil-fired” unit limits. Those revisions would be consistent with EPA’s statements in the preamble regarding applicability.¹⁹⁸

EPA also states in the preamble¹⁹⁹ and in § 63.9982(a) that units combusting “natural gas at greater than or equal to 98 percent” of the unit’s annual fuel consumption are not affected units under this proposal. Because other provisions in the rule state that they apply to “coal-fired” units, the definition of “coal-fired” should be revised to reflect the 98 percent or more exclusion for combustion of natural gas.

The rule also includes several exclusions related to combustion of “natural gas,” which is not defined. Section 63.10042 should be revised to include a definition of natural gas. EPA should also consider whether combustion of synthetic gaseous fuels that are not derived from coal (*e.g.*, digester gas and landfill gas) also should be eligible for the 98 percent exclusion. UARG believes that they should be.

11. Other Issues

UARG has identified the following additional issues. Section 63.10020(c) states that any period for which a monitoring system is out of control and data are not available constitutes a “deviation.” UARG objects to labeling each period when a monitor fails a QA/QC test and is therefore “out-of-control” as a “deviation” of the requirement to monitor. Monitoring systems

¹⁹⁷ Proposed 40 C.F.R. §§ 63.9991, 63.10042.

¹⁹⁸ 69 Fed. Reg. at 4662.

¹⁹⁹ *Id.* at 4664.

no matter how well maintained will occasionally fail a QA/QC test. As long as the source takes appropriate action, no deviation from the requirement to monitor has occurred. UARG is especially concerned about this provision given the uncertainty surrounding the ability of the Hg CEMS to satisfy the proposed standards in PS 12A on an ongoing basis.

Defining failure of a QA/QC test as a “deviation” could be problematic from a Title V reporting and compliance standpoint once the requirements are incorporated into a Title V permit. Because some states require “prompt reporting” (*e.g.*, within 24 hours) of all deviations, such a requirement could become overly burdensome. Moreover, because states are allowed to adopt their own definition of “deviation,” some periods could become “violations.” EPA should remove the statement regarding deviations or limit it (consistent with § 63.10020(a)) to the removal of a monitoring system from service that is not associated with a “malfunction, repair, or required quality assurance or control activities.”

Table 2 states that each coal-fired unit subject to a limit in § 63.9990 must demonstrate “initial compliance” by establishing “a site specific [mercury] limit according to the procedures in § 63.10009 and report[ing] the limit in your Notification of Compliance Status.”²⁰⁰ This articulation of the initial compliance demonstration is not consistent with the rules. First, many units do not establish site-specific limits, and it is not clear how simply reporting a limit establishes compliance. Second, § 63.10009 does not call for reporting of a limit, but rather calculation of a 12-month rolling average. Third, there is no requirement in § 63.10030(e), addressing “Notification of Compliance Status,” to report the applicable limit. The Notification requires reporting of the results of the “initial compliance demonstration.” EPA should fix these errors and inconsistencies.

²⁰⁰ *Id.* at 4728.

F. The Three Year Compliance Deadline for EPA’s Proposed MACT Standards Should Be Extended

EPA has proposed to require compliance with its MACT limits within three years of the effective date of those limits. In so doing, EPA has followed the requirements of CAA § 112(i)(3)(A). EPA has not proposed to extend this compliance time, as it has discretion to do under the CAA, but has requested comments on whether an extension is justified. As a practical matter, all electric utility steam generating units will not be able to comply with the proposed MACT limits within three years. Full compliance may require five years or more. If EPA proceeds to set MACT limits, it must make use of the compliance extensions provided in the CAA to provide an orderly retrofitting of mercury control equipment on coal fired power plants.

1. Practical Limitations Prevent All Existing Units from Meeting a Three-Year Deadline

EPA’s proposed MACT limits will require many units to retrofit mercury control technology. The retrofit process is complex and includes design, procurement, the assembly of skilled labor and construction equipment, and permitting. All retrofits must also be scheduled so as to ensure reliable electric service to the public throughout the retrofit period. For mercury control, this process is complicated because mercury-specific control equipment is not commercially available.²⁰¹

Electric utility steam generating units will attempt to comply with EPA’s MACT limits in a variety of ways. Many bituminous units may rely on the installation of SCRs and scrubbers. A

²⁰¹ See Cichanowicz Technical Comments, Section 7 (Attachment 8); *see also* “Industry Stakeholder Recommendations to EPA,” letter to co-chairs of the EPA Utility MACT Working Group at 6 (Sept. 6, 2002) (Docket No. A-92-55-II-E-90). J.E. Cichanowicz, Michael Hein, & Jim Marchetti, “Utility Industry Response to the CAIR Mandates: Estimates of Technology Retrofit and Schedule,” (Mar. 30, 2004) (“Utility Industry Response”) (Attachment 10); 69 Fed. Reg. at 4675 (discussion of beyond-the-floor options for existing units).

survey of UARG members performed in association with UARG's comments on EPA's proposed CAIR shows that SCR installation requires an average of 24 months, while FGD projects average at least 32 months.²⁰² Predictions about the time needed to install mercury-specific control equipment like activated carbon injection ("ACI") are difficult, if not impossible, because as EPA has noted in the Supplemental Notice, mercury-specific control technology will not be available for commercial deployment on a wide scale until "after 2010, or perhaps later."²⁰³ EPA estimates that wide-scale availability of advanced mercury control technology such as ACI will not occur until 2015, or later, "assuming sufficient research development and demonstration."²⁰⁴

Industry experts agree with EPA's assessment, noting that there have only been four large scale demonstrations completed using ACI as a control technique.²⁰⁵ While additional testing is ongoing with results expected in late 2004 and 2005, there are insufficient data and equipment availability to consider ACI currently a valid control option.²⁰⁶ Even if ACI was a commercially available technology, questions remain about the availability and adequacy of activated carbon supplies and the bag material for polishing baghouses.

²⁰² Utility Industry Response at 10 (Attachment 10). During EPA's Utility MACT Working Group meetings, industry participants estimated that scrubber installation would take 36 months. Industry Stakeholder Recommendations to EPA at 7.

²⁰³ 69 Fed. Reg. at 12403. The fact is, this statement in the Supplemental Notice essentially satisfies the criteria for granting an extension of the compliance deadline as outlined in section B, below.

²⁰⁴ *Id.*

²⁰⁵ *See*, Larry S. Monroe, "Commercialization of Emission Control Technologies in the U.S. Utility Industry, with a particular focus on mercury controls," June 28, 2004 (Attached to the comments of Southern Company).

²⁰⁶ *Id.* at 6.

In addition to the time needed to plan, design, and install new equipment, a number of states impose permitting requirements on the disposal of new waste streams in solid waste landfills.²⁰⁷ In Georgia, it is anticipated that 24-36 months will be needed just to obtain necessary landfill permits for a new waste stream.

Another significant problem in meeting a three-year MACT compliance date is the availability of skilled labor. Despite EPA's optimistic estimates that there may be sufficient labor to complete the retrofits required to comply with the proposed 2010 CAIR Phase I deadline, there is no evidence that there will be sufficient skilled labor to meet both the MACT and CAIR deadlines,²⁰⁸ nor will the current skilled labor force be able to satisfy the demands generated by the three-year MACT deadline.

EPA noted in 2002, and reaffirmed in 2004, that "the availability of boilermakers [is] the most important short-term consideration" affecting the ability of sources to install pollution control equipment.²⁰⁹ The supply of boilermakers cannot expand rapidly. According to the International Brotherhood of Boilermakers, a registered boilermaker apprenticeship program

²⁰⁷ Utility Industry Response at 10 (Attachment 10). This is significant for those units that may adopt control procedures that result in a new waste stream such as activated carbon laden with mercury.

²⁰⁸ Indeed, for CAIR, UARG believes the evidence shows that compliance with Phase I would not be feasible before 2012.

²⁰⁹ EPA, Clean Air Markets Division, "An Analysis of the Impact of Boilermaker Labor Availability on the Installation of Pollution Control Equipment," Memo to Docket at 1 (Jan. 28, 2004) (citing EPA Report "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-pollutant Strategies," October 2002). (Docket No. OAR-2003-0053-0008). UARG agrees. The primary resource limitation making compliance with Phase 1 of CAIR infeasible before 2012 is availability of boilermakers. Utility Industry Response, at 3 (Attachment 10).

takes 6,000 hours to complete.²¹⁰ Assuming that the majority of apprentices take four years to complete the program, and given that there will be attrition in the current boilermaker pool due to retirement and other factors, it is unlikely that there will be sufficient boilermakers available to meet the demand created by the MACT and CAIR rules.

Regardless of labor availability, however, EPA's own analysis underscores that a 2008 MACT limit cannot be achieved by all units. The 2008 MACT level results in approximately a 34-ton "cap" on utility emissions, which is comparable to the CAIR Phase 1 co-benefits mercury emission level projected by EPA. The proposed CAIR Phase 1 compliance deadline is 2010, while the MACT deadline is 2008. EPA's own analysis established that the 2010 co-benefit cap cannot be reached until 2010, yet it is attempting to impose a similar cap in 2008 for a program that does not include the flexibility of a cap-and-trade approach.²¹¹

Another factor that may affect compliance is the availability of construction equipment, such as very large construction cranes.²¹² Without this specialized construction equipment, compliance deadlines cannot be met.

Finally, even if a unit is able to meet the early 2008 compliance deadline, there will probably be little time for start-up testing to ensure the retrofit operates safely. Start-up testing normally takes several months.²¹³

²¹⁰ See <http://www.bnap.com/process/index.htm>. Normally, the entire apprenticeship is completed in four years, though it may take less time if the individual has prior welding experience.

²¹¹ As discussed above, UARG, in its CAIR comments, notes that the CAIR Phase 1 2010 deadline should be extended to 2012.

²¹² Industry Stakeholder's Recommendations to EPA at 7.

²¹³ *Id.*

As the above discussion shows, there are a number of factors that will affect a unit's ability to comply with the three-year deadline. When resources are scarce, small units and systems especially will face significant difficulties gaining access to available resources. Single-plant operators and smaller systems will be forced to wait in line to obtain necessary equipment and technology as vendors provide services to their largest customers first.

2. EPA Should Provide a One-Year Extension For All Existing Units

CAA § 112(i)(3)(B) grants the EPA Administrator discretion to extend the deadline for existing sources by one year "if such additional period is necessary for the installation of controls." EPA has requested comment as to whether a one-year extension "should be granted for facilities required to install controls in order to comply with the section 112 MACT rule."²¹⁴ For the reasons detailed above, UARG urges EPA to use its discretionary authority and extend the compliance deadline for all existing units.

EPA has recognized that necessary mercury control technology will not be available on a wide commercial basis until 2010 or later. Even if the technology is available, it will take more than three years to plan, permit, and complete the construction of the retrofits necessary to comply with this rule. Congress gave the Administrator discretionary authority to extend the compliance deadline presumably with the realization that there would be cases where more than three years would be needed to comply with MACT limits.

In the proposed rule, EPA expresses a concern that it cannot grant an extension to all units because some units are currently in compliance with the proposed MACT limits and EPA cannot extend the compliance time for those units.²¹⁵ At present, it is impossible to know which

²¹⁴ See 69 Fed. Reg. at 4682.

²¹⁵ *Id.*

units are currently complying with EPA's proposed limits and which ones are not. No unit is currently monitoring mercury emissions to be able to assess its compliance. Individual plant emission estimates based on 1999 ICR results are not a reliable basis for deciding whether a unit can comply with the MACT limit without any action. Furthermore, given the complexities of the CAIR and the mercury MACT proposals, many units will be forced to change their current operations in order to comply with both rules. EPA should issue a blanket one-year extension to all units.

An extension of the compliance date is in keeping with Congress' prior recognition of the time needed by electric utilities to retrofit control equipment. For example, Congress understood the size, complexity, and national importance of the electricity generating utility industry acknowledging, for instance, that the retooling of the industry to comply with sulfur emission control goals would take much more than three years. In fact, Congress gave most electric utility units until 2000 to comply with the Acid Rain/Sulfur Dioxide program.²¹⁶ This was a full ten years from the passage of the Clean Air Act Amendments and seven years from the date EPA finalized the trading program's "core rules."²¹⁷

Congress' appreciation for the difficulty associated with technology retrofits was also evidenced by § 182 of the 1990 CAA Amendments. In general, this section reflects the governing principle that the more seriously an area is deemed out of attainment with the national ambient air quality standards for ozone, the more time Congress provided to allow affected sources in that area to plan, purchase and install retrofit technology. No area that likely would

²¹⁶ CAA § 405(a); 42 U.S.C. § 7651d(a).

²¹⁷ See 58 Fed. Reg. at 3590 (Jan. 11, 1993).

require significant retrofits to attain was required to attain in less than *six years*, while other areas were given as long as *20 years* to attain.

3. Additional Extensions Should Be Granted Under the Presidential Exemption Provision on a Case-by-Case Basis

CAA § 112(i)(4) allows the President to exempt “any stationary source from compliance” for any number of two-year periods if doing so is in the national security interest and if the technology to implement the standard is not available. Both findings can be made regarding the implementation of EPA’s proposed MACT rule.

As evidenced by the blackouts that unexpectedly hit the eastern United States in 2003, insufficient power availability can have a dramatic impact on the country. Retrofitting units to comply with the mercury MACT will require units to be taken off-line during the construction phase. Only so many plants can be taken off-line in a given region before the power grid in that region -- and perhaps throughout the nation -- is affected. According to the Energy Policy Report released by the Vice President’s Energy Task Force, there is a currently a lack of energy generation capacity in this country, causing an imbalance between supply and demand. This imbalance “will inevitably undermine ... our national security.”²¹⁸ This imbalance, or supply shortage, will only be exacerbated by taking multiple units off-line concurrently to install mercury control equipment.

As a practical matter, if all units are forced to comply with the three-year deadline, many of those units will need to be taken offline toward the end of the three-year period. There would be a significant impact on energy availability if units are required to undertake the construction phase of the retrofit process concurrently.

²¹⁸ Report of the National Energy Policy Development Group, “National Energy Policy,” (May 2001), at viii.

Sufficient technology is not currently available on the scale needed to ensure a rapid and safe retrofit process in the time period established under the CAA. Mercury-specific controls necessary to comply with the rules as proposed are, at the very least, in a demonstration phase.²¹⁹ EPA estimates that wide-scale availability of advanced control technology like ACI will not occur until 2015 -- a full seven years after the proposed MACT compliance deadline.²²⁰

Additionally, the “technology to implement the standard” includes the material necessary to install scrubbers and SCR units. Without the necessary materials, such as activated carbon, bag material, and construction equipment, units cannot be retrofit with control technology, and the standard cannot be implemented. As discussed above, there is insufficient construction equipment in the United States, such as very large cranes, to meet the demand that will be created by the very short MACT deadline. In short, there is a lack of available control technology to comply with the standard by EPA’s proposed deadline. Thus, grounds exist for granting at least a two-year presidential extension for many coal-fired units.

4. Compliance Extensions Should Be Included as Part of the Final Rule

As just explained, the planning, design, acquisition, and construction of mercury MACT retrofits will take more than three years. If EPA does not provide compliance extensions as part of the final rule, it would be tantamount to rejecting the requests for extension, since units will have to begin the planning and acquisition process upon publication of the rule. EPA must address the compliance deadline issues in any final MACT rule.

²¹⁹ See 69 Fed. Reg. at 12403.

²²⁰ *Id.*

V. EPA's MACT Proposal for Oil Fired Units

EPA's decision to list oil-fired units under § 112(c) stems from some undefined concern about nickel emissions. EPA does not have statutory authority to regulate nickel emissions from oil-fired units based solely on screening level risk assessments conducted as part of EPA's Utility Study to Congress. Prior to proceeding with any regulation of nickel emissions from oil-fired units, EPA must review and consider current information on nickel emissions, recent speciation studies, new risk assessments based on current data, and the fact that a number of the units that had the highest predicted risks in EPA's earlier screening risk assessments no longer burn oil as their primary fuel source.

Even if EPA can demonstrate a public health concern associated with nickel emissions from oil-fired units, its MACT proposal still has a number of problems. Foremost among those is the extremely limited database EPA used to set the MACT floors. The emissions from twelve units, some of which were equipped with pilot-scale control equipment, are an insufficient basis for industry-wide standards.

A. **EPA Does Not Have Legal Authority to Regulate Nickel Emissions from Oil-Fired Units**

As discussed in Section II above, electric utility steam generating units are treated uniquely under § 112. Section 112(n)(1)(A) requires EPA to perform a study of the hazards to public health reasonably anticipated to occur as a result of HAP emissions from electric utility steam generating units and then to regulate those HAPs where regulation is "appropriate and necessary" to protect public health.²²¹

²²¹ See *id.* ("[t]he EPA interprets section 112(n)(1)(A) as only authorizing regulation of utility units under section 112 with respect to HAP emissions from such units that EPA has determined are 'appropriate and necessary' to regulate under section 112 because they are
(continued...)

EPA's December 2000 listing decision is devoid of factual bases for the decision to list oil-fired electric utility steam generating units under § 112(c). The listing notice focuses almost exclusively on mercury emissions as the primary reason for listing electric utility steam generating units under § 112(c). Almost as an aside, EPA notes that nickel is one of a handful of metals that are "of potential concern for carcinogenic effects." EPA adds that "although the results of the risk assessment indicate that cancer risks are not high, they are not low enough to eliminate those metals as a potential concern for public health."²²² In the conclusions section of the listing notice, EPA cites only findings about mercury and its public health impacts. Despite the absence of any health finding regarding nickel, EPA nevertheless includes oil-fired units on the list of § 112(c) source categories.

One must turn to EPA's 1998 Utility Study to Congress to find an analysis of the health risks posed by nickel emissions from oil-fired plants. The nickel risk assessments in the Utility Study were performed at a screening level, and relied on conservative assumptions about the species and the toxicity of nickel emitted from oil-fired units.

EPA based its nickel risk assessments on an assumption that half of all the nickel emitted from oil-fired units is as carcinogenic as the most carcinogenic form of nickel.²²³ According to EPA, "[t]here are substantial uncertainties associated with nickel speciation. In this analyses, as a conservative assumption, the mix of nickel compounds emitted by oil-fired utilities was assumed to be 50 percent as carcinogenic as nickel sub-sulfide, which is a class A human

reasonably anticipated to result in a hazard to public health even after imposition of the other requirements of the CAA.")

²²² 65 Fed. Reg. at 79827.

²²³ Utility Study, at 6-7.

carcinogen.”²²⁴ Yet, EPA’s own speciation data indicated that “3 to 26 percent of nickel emission from oil-fired utilities are sulfidic nickel,” so its screening level assumption at least doubled the risk that EPA calculated for nickel emissions. In fact, EPA only has speciated nickel data from two oil-fired units.²²⁵ Testing at those two sites revealed a number of nickel species, including nickel, sulfidic nickel, nickel monosulfide, nickel sulfide, nickel sub-sulfide, metallic nickel, and oxidic nickel. The average values of the two test sites were: 58 percent soluble nickel, 3 percent sulfidic nickel, and 39 percent nickel oxides.²²⁶

Based on the data available, EPA’s risk assessment for oil-fired units determined that up to 11 of the 137 oil-fired plants were estimated to potentially present inhalation risks above 1×10^{-6} , with nickel considered to be the primary contributor to the cancer risk.²²⁷ According to EPA, “[i]f alternative methods and assumptions were used to study the HAP emission from utilities, the results of [its risk modeling] would likely be somewhat different.”²²⁸ The Utility Study notes that EPRI developed its own study paralleling the Utility Study, and that while “[m]any of the same emissions data were used and similar risk assessment methods were

²²⁴ *Id.* at 6-7. Nickel releases are not of equal health effect since the various nickel compounds vary significantly in terms of their toxicity. EPA’s IRIS database lists nickel subsulfide and nickel refinery dust as Class A carcinogens and nickel carbonyl as a probable carcinogen. EPA has made no determinations for other nickel compounds, though it has posted information as to nickel soluble salts on its IRIS database.

²²⁵ *See id.* at 6-47.

²²⁶ *Id.*

²²⁷ *Id.* at ES-8. Despite this assessment, EPA states at the end of the Utility Study that additional research is necessary on the speciation issue. *Id.* at 14-8. “[In fact,] the cancer incidence due to nickel emissions could possible be as low as zero.” *Id.* at 6-49.

²²⁸ *Id.* at ES-26.

utilized, ... [p]opulation inhalation risks [for nickel emissions] were determined by the EPRI to be insignificant.”²²⁹

The EPRI study “brought together information on airborne trace substances, analytical methods, and results of recent and ongoing research,” that EPRI and other organizations had undertaken. EPRI looked at existing research to assess the health risk associated with the emission of certain trace substances from electric utility power plants. Its analysis focused on sixteen substances “most likely to be found in utility stack emissions.”²³⁰ This included nickel. EPRI’s study considered available data from a limited number of field tests on oil-fired units. The report ultimately found that trace substance emissions from oil-fired units would not pose significant long-term risks (either carcinogenic or non-carcinogenic) to human health.²³¹

In a report released in November 2003, by the Energy and Environmental Research Center (“EERC”), actual emissions from two oil-fired utility boilers were studied for their respective nickel content -- both quantity and species. EERC selected two utility boilers that were representative of residual oil-fired units.²³² It analyzed samples using the most recent

²²⁹ *Id.*

²³⁰ EPRI, “Electric Utility Trace Substances Synthesis Report,” vol. 1, p. 1-5 (1994) [hereinafter, “EPRI Study”] (Docket No. OAR-2002-0056-2039).

²³¹ *Id.* at iii, iv. According to the EPRI Study, “[f]or the roughly 600 plants investigated [including all fuel types], the expected increase in individual cancer risk, incorporating exposure assumptions associated with maximum exposure over a 70-year life span, did not exceed [EPA’s acceptable risk level of] 1.7 in one million. Of this entire group of plants, only 3 approached exposures leading to a cancer risk greater than 1 in a million” for an individual facing “maximum exposure.”

²³² Energy and Environmental Research Center, “Nickel Species Emissions Inventory for Oil-Fired Boilers,” Final Report 03-EERC-11-05, at 3 (Nov. 2003) (Docket No. OAR-2002-0056-0018).

testing methods to determine the species of the nickel emitted.²³³ Direct speciation measurements showed a noticeable lack of sulfidic nickel emitted. The chemical speciation of nickel in fly ash from the combustion of 0.9 and 0.3 wt% sulfur residual oils revealed mostly $\text{NiSO}_4 \times \text{H}_2\text{O}$ and nickel oxide compound mixtures and a noticeable lack of carcinogenic Ni_3S_2 or nickel sulfide compounds.²³⁴ EPA should use these data to produce more realistic risk assessments.²³⁵

EPA should also consider recent DOE information showing that some of the oil-fired plants deemed to pose the greatest risk for nickel inhalation in the 1998 Utility Study either no longer operate, or have changed their primary fuel from oil to another fuel, such as natural gas.²³⁶

The evidence in the rulemaking record fails to show that there is a public health risk associated with nickel emissions from oil-fired units. Absent a proven risk, regulation of nickel is not “appropriate and necessary” under the CAA and EPA should rescind its listing decision for oil fired units.

²³³ *Id.*

²³⁴ *Id.* at 16-17.

²³⁵ In fact, EPA notes in the Utility Study that “further assessment would be needed in several areas to gain a better understanding of the actual risks posed by electric utilities.” Utility Study at 6-1. Now that a “further assessment” has been completed, it should be considered.

²³⁶ *See, e.g.*, Existing Electric Generating Units in the U.S. by State, Company and Plant, 2002, available at <http://www.eia.doe.gov/cneaf/electricity/page/capacity/existing2002.xls>. As an example, the Bryan, Devon, and Alamos stations now list natural gas as their primary fuel source.

B. Assuming EPA Establishes Its Legal Authority to Regulate Nickel Emissions from Oil-Fired Units, the Existing Database Is Insufficient to Set MACT Limits

EPA has based its nickel MACT floor analysis on an unrepresentative, sparse database. At the very least EPA should obtain more data from representative units before proceeding with nickel MACT limits.

Documents on EPA's website show that the nickel MACT floor is based on approximately three hours of operational data from twelve units.²³⁷ Nickel emissions ranged from 1.6 lbs/TBtu to 2167 lb/TBtu. The lowest-emitting unit was equipped with a "pilot-scale pulse-jet fabric filter," a developmental technology not in commercial operation anywhere in the country.²³⁸ The large variability in availability dates should be reason enough for EPA to seek additional information before setting a MACT floor.

Additionally, EPA's database did not consider emission from a sufficient number of units. Assuming there are approximately 130 oil-fired units in the country, data from twelve units is simply too small a data set to determine a MACT floor.²³⁹ Congress intended for EPA to obtain data from enough sources to establish a standard that is achievable by a reasonable group of sources. EPA has not done that.

²³⁷ Two units were tested twice, for a total of 14 data points.

²³⁸ See Oilhaps.xls available at <http://www.epa.gov/ttn/atw/combust/utlto/utoxpg.html>.

²³⁹ This is particularly the case given EPA's interpretation of § 112(d)(3)(A). EPA interprets that provision to require it to set the MACT floor for existing units based on the top 12% of the sources for which it has data. Thus, 12% of 12 sources is 1 or 2 sources. In either case, this is too small a number of sources to set a MACT limit for oil-fired units.

C. Exclusion of Certain Oil-Fired Units

UARG supports EPA's decision to exclude units that burn oil less than 2% of the time from compliance with the nickel emission limits applicable to oil-fired units.²⁴⁰ UARG believes that this threshold should be raised to coincide with the 10% limit used in the Acid Rain Program.²⁴¹ EPA states in the proposed rule that any health risk associated with nickel emissions from oil-fired units is "not high." If 90% of the fuel burned by a unit is not oil, then it is presenting about 1/10th of the risk as a unit that is burning oil 100% of the time. Since units that burn oil and natural gas base their decisions, at least in part, on market fluctuations and on which fuel is more readily available, allowing a slightly higher cut-off limit will provide units with greater operational flexibility without any significant affect on the already-minimal health risk associated with nickel emissions.

Regardless of the threshold level, EPA should clarify precisely how this exemption will be determined. There are inconsistencies in the proposed rule. The preamble states that a unit is considered to be an oil-fired unit and subject to the nickel MACT if it is equipped to fire oil and/or natural gas, and if "it fires oil in amounts greater than or equal to two percent of its *annual fuel consumption*."²⁴² However, elsewhere preamble states that the nickel MACT would not

²⁴⁰ "EPA considers a unit to be an oil-fired unit if ... it fires oil in amounts greater than or equal to two percent of its annual fuel consumption." 69 Fed. Reg. at 4705.

²⁴¹ See 40 C.F.R. § 72.2 (defining oil-fired as combusting fuel oil for more than 10 percent of the average annual heat input during the previous three calendar years or for more than 15% of the annual heat input for any one of those years).

²⁴² 69 Fed. Reg. at 4705.

apply to units that combust natural gas “greater than 98 percent *of the time*.”²⁴³ EPA should clarify that the exemption is based on the oil used as a percentage of the unit’s annual heat input.

EPA should consider additional alternatives for unit-exemptions, as well. For instance, units with a very low capacity factor, such as 5% or its equivalent, or units that are in operation for only a limited number of hours in a given year, should be exempt.

D. Exemptions of Distillate Oil Units

EPA proposes exempting oil-fired units that burn exclusively distillate oil from compliance with the nickel emission rules under both regulatory alternatives.²⁴⁴ UARG supports this exemption.

According to EPRI’s analysis, in 1990 approximately 87% of the units that used oil for fuel burned residual oil. The remaining 13% used other fuels, some using distillate oil.²⁴⁵ EPRI also noted that distillate fuel oil contains fewer trace constituents than residual fuel oil.²⁴⁶

EPA studies have shown that nickel content decreases depending on the grade of fuel oil used (*i.e.* #2 distillate fuel oil has a lower nickel content than #6 residual fuel oil)²⁴⁷ and that the greater the nickel content in the fuel, the higher the rate of nickel emissions.²⁴⁸ Given the much

²⁴³ *Id.* at 4657.

²⁴⁴ *See id.* at Reg. 4663 and 4705.

²⁴⁵ EPRI Report at 4-15.

²⁴⁶ *Id.*

²⁴⁷ *See* “Locating and Estimating Air Emissions From Sources of Nickel,” EPA- 450/4-84-007f, at 111 (Mar. 1984) (listing the average nickel content of residual (no. 6) fuel oil from 10 - 48.5 parts per million (“ppm”) (depending on sulfur content), and the range of nickel content for distillate (no. 2) fuel oil as <0.02-1.7 ppm).

²⁴⁸ *Id.* at 112.

lower nickel emissions from units burning distillate oil, they should be exempt from any MACT limits for nickel.

EPA should also address how this rule will be applied to units that burn only distillate oil and natural gas. Despite the discussion in the preamble concerning dual-fired units, it is not clear whether units that burn 50% distillate oil and 50% natural gas (or any other combination of distillate oil and natural gas, but where the oil the unit burns is solely distillate) would qualify for this exemption since the unit is not “burning any oil other than distillate,” and it is burning distillate oil “exclusively.” The text of the proposed rule is not helpful because it apparently includes a typographical error.²⁴⁹ Units that burn exclusively distillate oil, in combination with natural gas, should be exempt.

E. Beyond-The-Floor Conclusion That Fabric Filters Are Not a Viable Option for Oil-Fired Units

According to the proposed rule, “[t]here has not been a new oil-fired unit constructed in the U.S. since 1981. If a new unit is constructed, the only technology that might offer emissions control better than the proposed new unit MACT limits is the use of fabric filtration.”²⁵⁰ However, due to the nature of oil-fired emissions, EPA does not consider fabric filtration to be a viable option for oil-fired units.²⁵¹

UARG agrees with this assessment. Coal-fired unit emissions and oil-fired unit emissions are inherently different. The particulate matter produced from the combustion of coal is characterized as dry allowing a fabric filter to effectively remove the particulates. Oil-fired

²⁴⁹ See 69 Fed. Reg. at 4721 (proposed rule § 63.9991(b)).

²⁵⁰ *Id.* at 4680.

²⁵¹ *Id.*

units produce ash having very different characteristics. Oil-plant ash quickly clogs a fabric filter and the filter ceases to perform in its designed manner. Fabric filters are not a viable control technology for oil-fired units.

F. Monitoring and Compliance Issues Specific to Oil-Fired Units

The following describes the monitoring and compliance issues in proposed Subpart UUUUU that are specific to oil-fired units. Issues that apply to both oil-fired and coal-fired units are described above in section IV.E.

1. Proposed Compliance Method

EPA's proposal for establishing compliance with the nickel limit is set out in various provisions and summarized in Table 1.²⁵² To initially determine compliance, EPA proposes to require initial and periodic performance testing using stack testing methods.²⁵³ During that testing, EPA also proposes to require the continuous monitoring of operating parameters using continuous parameter monitoring systems ("CPMS") data and establishment of a site-specific *operating limit* for the relevant parameter(s) that would be used to establish "continuous compliance" in between periodic performance tests.²⁵⁴

For units using an ESP to meet the nickel limit, EPA proposes requiring monitoring of *voltage* and *secondary current* (or total power input) to the ESP and operation such that the hourly average values do not fall below the value measured during each initial or subsequent performance test.²⁵⁵ Units using some other control device or combination of control devices, or

²⁵² 69 Fed. Reg. at 4728.

²⁵³ Proposed 40 C.F.R. §§ 63.10006, 63.10007.

²⁵⁴ *Id.* at §§ 63.9991(c) and (d), 63.10008(a) and (b).

²⁵⁵ *Id.* § 63.9991(c).

wishing to use an alternative parameter for an ESP, must apply to the Administrator for approval of an “alternative” monitoring system under § 63.8(f).²⁵⁶ Each CPMS would have to complete a minimum of one cycle of operation for each successive 15-minute period and have a minimum of four successive cycles of operation for a valid hour of data.²⁵⁷ Sources also must develop and submit a “unit-specific monitoring plan,” conduct a “performance evaluation” for each CPMS,²⁵⁸ and record the results of “each inspection, calibration, and validation check for a CPMS.”²⁵⁹

a. Periodic Performance Testing

UARG believes that it is reasonable to require sources to conduct initial performance tests to demonstrate that the chosen control devices are capable of achieving any reductions necessary to meet applicable emissions limitations, and that a requirement for periodic retesting is not unreasonable. Although UARG members have little experience with Method 29, UARG recognizes that other types of facilities have used the method for some time. UARG is concerned, however, that the notice proposed by EPA for performance testing is unnecessarily restrictive and could actually make it more difficult for EPA and state officials to observe tests, since tests scheduled too far in advance are more likely to be rescheduled. Specifically, UARG does not believe that the proposed requirement for 60 days notice of performance testing is reasonable as applied to an annual testing requirement.²⁶⁰ Rather, 30 days notice should be

²⁵⁶ *Id.* at § 63.9991(d).

²⁵⁷ *Id.* at § 63.10008(b)(1) and (2).

²⁵⁸ Unit-specific monitoring plans and performance evaluations are required for each “continuous monitoring system” (“CMS”). CMS is defined in § 63.2 to include CPMSs.

²⁵⁹ Proposed 40 C.F.R. § 63.10000(c) and (d), § 63.10008(b)(3).

²⁶⁰ *Id.* at § 63.10030(d).

sufficient and would be consistent with the notice requirements under the NSPS and the recently signed MACT for industrial boilers.²⁶¹ UARG also requests that EPA add a reference to the provisions in § 63.7(b)(2) addressing rescheduling of tests following notice.

b. Enforceable Operating Limits

UARG disagrees with EPA's proposal to establish operating parameter levels monitored during performance testing as future *operating limits*. A requirement to maintain the operating parameter levels monitored during performance testing would unreasonably restrict source (and control device)²⁶² operation *without any showing by EPA that such restrictions are necessary to achieve the proposed MACT limits*. Given the lack of concise correlations between the control device operating parameters and stack emissions, UARG believes any continuous monitoring requirements for those pollutants should employ concepts similar to those adopted in EPA's Compliance Assurance Monitoring ("CAM") rule at 40 C.F.R. Part 64.²⁶³

UARG explained its position on this issue in detail in comments on EPA's January 13, 2003 proposed MACT for industrial boilers.²⁶⁴ EPA's initial response to UARG's comments

²⁶¹ See 40 C.F.R. § 60.8; 63.7545(d).

²⁶² Sources attempting to minimize these restrictions will be forced to deliberately decrease deliberately the performance of their controls during annual testing to allow testing as close as possible to their emissions limit. EPA's proposal implicitly recognizes this by requiring testing at the "representative operating conditions that are expected to result in the highest emissions of Ni." Proposed 40 C.F.R. § 63.10007(a)(2).

²⁶³ As EPA has previously recognized in the context of the NSPS and the CAM rule "many sources operate well within permitted limits over a range of process and pollution control device operating parameters," and requiring sources to continuously maintain parameters that "happened to exist" during the most recent performance test "may not be possible or wise." 62 Fed. Reg. 54900, 54926-27 (Oct. 22, 1997).

²⁶⁴ See 68 Fed. Reg. 1660 (Jan. 13, 2003). UARG's comments on EPA's proposal are identified as Docket No. OAR-2002-0058-0413.

was to claim that it did not have authority to employ a CAM concept because the statute requires more than a “reasonable assurance of compliance.”²⁶⁵ EPA also noted that exceedances of operating parameters are not automatic violations, because whether a deviation constitutes a violation is up to the “discretion of the entity responsible for enforcement of the standard.”²⁶⁶ EPA’s responses are not adequate.

First, there is no statutory provision establishing a more stringent standard for showing compliance with a MACT than a NSPS, or any other emission standard to which CAM applies.²⁶⁷ In fact, in two cases reviewing MACT standards, the D.C. Circuit has described EPA’s obligation in terms of showing a “reasonable assurance of compliance.”²⁶⁸ The Court has also noted that EPA has “broad discretion in selecting a monitoring regime that ensures compliance.”²⁶⁹ UARG believes that EPA not only has discretion to use a CAM approach under MACT, but the obligation to establish that such an approach is not sufficient.

Second, EPA’s claim that the enforcement discretion to determine whether a deviation is a violation should provide comfort to sources is ridiculous. UARG’s concern is not just that the deviation would be deemed an automatic violation, but that it could be deemed a violation *at all*

²⁶⁵ EPA Response to Comments, Docket No. OAR-2002-0058-0611, at 133.

²⁶⁶ Final National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (“Final IB MACT”), at 110-20.

²⁶⁷ EPA exempted MACT from CAM, *see* 40 C.F.R. § 64.2(b)(1)(i), not because the legal standard was different, but because EPA understood that because the MACTs had not yet been promulgated EPA would be able to address compliance assurance directly in each MACT standard. *See, e.g.*, CAM Response to Comments, Part III, at Section 6.1.8, comment c (Oct. 2, 1997).

²⁶⁸ *Sierra Club v. EPA*, 353 F.3d 976, 990 (D.C. Cir. 2004) (citing *NRDC v. EPA*, 194 F.3d 130, 136 (D.C. Cir. 1999) (upholding EPA’s CAM rule); *National Lime*, 233 F.3d at 635.

²⁶⁹ *Sierra Club v. EPA*, 353 F.3d at 990.

without some showing that the nickel standard would have been violated. EPA must explain why a CAM approach would not provide a reasonable assurance of compliance.²⁷⁰

UARG also objects to EPA's use of an hourly average to define the operating parameter limit.²⁷¹ Performance tests require three runs of at least one hour each, which is a minimum of three hours of data.²⁷² Operating parameters recorded during such a test will also be based on three hours of data. Operating parameter values used to assure compliance with what is essentially a three-hour performance test should be based on a three-hour average.

c. Requirements for CPMS

EPA proposes a number of requirements for CPMSs, including such things as minimum data points per hour, performance evaluations, and calibration checks.²⁷³ EPA never explains, however, how these various requirements are to be met, even for the parameters identified in the rule. UARG is not aware of any general specifications for performance evaluations or calibration of voltage meters associated with ESPs and does not know what EPA intends by these requirements. Although UARG does not object to a requirement to quality assure parameter data using industry standards, EPA should not promulgate requirements without any understanding of whether or how they would be met. UARG is aware that EPA is working on proposed performance specification for CPMS. EPA should revise the provisions addressing

²⁷⁰ In the Final IB MACT, EPA provided some relief by establishing a 10 percent operating range around the parameter levels measured during the performance test. *See* Final IB MACT, definition of "minimum voltage or amperage," § 63.7575, and Table 7. At a minimum, EPA must provide the same relief in this rule.

²⁷¹ Proposed 40 C.F.R. § 63.9991(c).

²⁷² *Id.* at § 63.10007(a)(4).

²⁷³ *See id.* at §§ 63.10000, 63.10008.

CPMS to be less restrictive regarding the criteria for acceptance until appropriate procedures can be examined through a more comprehensive rulemaking.

d. Approval of Alternatives

The only operating parameters identified in the rule are for units using an ESP to meet the nickel standard. For all other control devices, and for alternatives to voltage and secondary current (or total power input) for ESPs, EPA's proposal requires sources to apply to the Administrator for approval of an alternative under § 63.8(f). Section 63.8(f), however, does not appear on its face to cover requests for approval of operating parameter requirements or alternatives to such requirements. If EPA intends to require sources to submit such requests, EPA should revise § 63.8(f) to reflect that new use, or revise Subpart UUUUU to establish a mechanism for approval.

2. Monitoring and Testing Deadlines

Under § 63.9991(b), EPA states that the nickel emissions limitation will apply "immediately" to any exempt oil-fired units (*i.e.*, units that fire 98 percent distillate oil) that subsequently combust a fuel other than distillate fuel. The rules, however, do not include any deadlines for demonstration of compliance with that limit. Obviously, even with a planned change in fuel, it likely is not possible to begin performance testing the minute the new fuel is combusted. As a result, EPA should clarify when and how compliance for these units must be demonstrated and should provide a reasonable amount of time for performance testing once the new fuel is combusted.

3. Compliance Calculations

Equations 6 and 7, in § 63.10009(e), for calculation of total mass emissions of nickel and nickel emissions rate are subject to the same criticisms as the equations for mercury emissions described above.²⁷⁴ EPA should review the equations and correct the problems.

4. Definitions

UARG also has identified a number of instances where the definitions do not reflect the proposed regulatory provisions or are otherwise unsupported. For example, EPA states in the preamble that a unit is considered to be “oil-fired” if it fires oil “in amounts greater than or equal to 2 percent of its annual fuel consumption.” The 2 percent value is intended to represent the amount that a gas-fired unit might use for start-up. Although the applicability provisions in § 63.9982(a) exclude units combusting “natural gas at greater than or equal to 98 percent” of the unit’s annual fuel consumption, this limitation on what units are considered “oil-fired” is not reflected in the definitions. The definition of “oil-fired” should be revised to reflect exclusion of oil consumption for “less than or equal to 2 percent” of fuel consumption. (The preamble statement is inconsistent with § 63.9982(a) in that it says that a unit that combusts exactly 2 percent oil would be oil-fired. Under § 63.9982, that unit would not be affected.)

In the proposed definitions of “distillate oil” and “residual oil” in § 63.10042, EPA has added a requirement related to the nitrogen content of the fuel. Nitrogen content is not a specification that is included in the cited ASTM definitions and is not a specification that is included in the definition used under Part 72 -- which is for “diesel fuel.” As a result, the definitions would appear to require testing to establish the nitrogen content. EPA has provided no rationale or justification for basing qualification of fuel as distillate or residual based on

²⁷⁴ *See id.* at 2-5 (Attachment 6).

nitrogen content. Accordingly, EPA should remove that specification and adopt a definition of “distillate oil” that is consistent with the definition in Part 72 and that references appropriate ASTM specifications.²⁷⁵

5. Other Issues

Section 63.10009(e) says units with nickel limits must determine initial compliance using the applicable procedures in paragraphs (e)(1) through (3), but there is no (e)(3) in the proposed rule. UARG assumes that (e)(3) was intended to establish a requirement to report the nickel emissions rate in the first semiannual compliance report. EPA should review these provisions and correct the reference.

Section 63.10031(b)(9)(viii) requires reporting of deviations of all monitored parameters, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices. This provision should be limited to parameters that are required to be monitored under § 63.9991(c) and (d). Otherwise the rule could require reporting of information that is not related to the rule.

VI. UARG Supports a Cap-and-Trade Approach and Favors a Federal Program Promulgated Under § 112(n)(1)(A)

UARG supports a mercury cap-and-trade approach because an emissions trading program will achieve greater mercury reductions from coal-fired power plants at far less cost than the proposed MACT alternative. The cap-and-trade program promulgated under the CAA Acid Rain provisions has proven highly successful in reducing air pollutant emissions. A similar program would work equally well in reducing mercury emissions from coal-fired power plants.

²⁷⁵ See RMB Technical Comments, at 2-6 (Attachment 6).

Mercury emissions are a global issue. About 75% of the mercury that deposits in the United States comes from sources outside the U.S.²⁷⁶ Mercury emissions from coal-fired power plants in the U.S. constitute only about 1% of annual global mercury emissions.²⁷⁷ EPRI modeling work predicts that reducing total mercury emissions from coal-fired power plants to 15 tons annually under a cap-and-trade program will reduce mercury deposition in the United States by only 6.9% -- from 166.1 tons per year to 154.6 tons per year.²⁷⁸ Given these factual realities, it makes little environmental or economic sense to impose command-and-control MACT requirements on every coal-fired power plant. A better way is to set a limit on total annual mercury emissions from electric utility steam generating units and then allow utilities to determine how best to achieve those reductions.

The cap-and-trade program proposed by EPA attempts to do this but it needs modification. UARG suggests a nationwide cap-and-trade program under § 112(n)(1)(A) having three phases. Phase 1 of the program would not specify a nationwide numeric mercury limit. Instead, the level of mercury emissions would be the level of reductions achieved by installing new control equipment to comply with the requirements of EPA's proposed CAIR rule -- the true co-benefits level. The reason for not setting a numeric limit for Phase 1 is that there is no way to know what level of mercury emissions will actually be achieved as a result of utilities' efforts to

²⁷⁶ See EPRI Comments at 13. This significant contribution from non-U.S. sources was confirmed by aircraft measurements conducted over the Pacific Ocean. See EPRI Comments at 14.

²⁷⁷ See *id.* at 11.

²⁷⁸ See *id.* at 53, Table B.1-6.

meet the proposed CAIR requirements. EPA recognized this problem when it requested comment on the level of mercury emissions that could be achieved in 2010.²⁷⁹

One uncertainty in predicting the level of co-benefits in 2010 is determining what control equipment will actually be installed. EPA, Charles River Associates, and UARG have all attempted to predict what control equipment each coal-fired unit will install to meet the proposed 2010 CAIR requirements. Each produced a different prediction. As a practical matter, there is no way of knowing which prediction, if any, will actually occur. Companies treat their compliance plans as confidential business information, and those plans can change over time.

A second uncertainty involves whether all of the control equipment that needs to be installed to meet the CAIR requirements can physically be installed by the 2010 deadline. As UARG has argued in its CAIR comments, the proposed 2010 CAIR caps cannot be achieved by that date.²⁸⁰ UARG's comments highlight the restrictions on manpower that will test many companies' ability to meet the CAIR requirements. If all of the control equipment that is projected to be installed by 2010 is not installed by that date, then the level of mercury co-benefits will be lower.

Even if one could accurately predict the new control equipment that will be installed and the schedule for its installation, there remains a third important uncertainty concerning the level of mercury control that can be achieved by scrubbers and SCRs. As noted in Section IV.A. above, the degree to which SCRs convert elemental mercury to ionic mercury is an open question. To date, only limited testing has been conducted on SCRs and the results are

²⁷⁹ 69 Fed. Reg. at 4698.

²⁸⁰ UARG, Comments on the Proposed Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (IAQR) (March 30, 2004) (Docket No. OAR-2003-0053-1017) (Attachment 11).

contradictory. At some bituminous coal-fired units equipped with SCRs, significant amounts of elemental mercury were converted to ionic mercury, yet at other units, very little conversion occurred. Very limited testing of subbituminous units equipped with SCRs has shown almost no conversion. The effect of SCRs on mercury emissions from lignite units has yet to be tested. There are also questions about whether scrubbers remove all of the ionic mercury that enters them or whether some amount of ionic mercury reduces to elemental mercury. These questions make it impossible to predict the level of mercury control that will be achieved at a unit equipped with a scrubber and/or an SCR.

For all these reasons, estimating the level of mercury co-benefits that will occur by the CAIR Phase 1 compliance deadline is simply a guess.²⁸¹ No matter what value EPA selects for the Phase 1 mercury co-benefits, it is unlikely to be correct. If the cap is set higher than the level of co-benefits that are actually achieved, then EPA will be criticized for creating a program that provides excess mercury allowances and that delays the date on which mercury emissions are ultimately reduced to 15 tons. On the other hand, if EPA sets the Phase 1 cap below the level of mercury co-benefits that is ultimately achieved by the installation of SO₂ and NO_x controls for Phase 1 CAIR compliance, then utilities will be forced to install more control equipment to produce additional mercury reductions. This result runs contrary to EPA's stated intent of having the first phase of its mercury cap-and-trade program reflect the co-benefits produced from meeting the CAIR requirements. This result would also produce economic inefficiencies and may adversely affect electric reliability in the United States. To avoid either of these outcomes, the most straightforward solution is not to set a numeric limit for Phase 1. If no numeric cap is

²⁸¹ Of course, any changes in the final CAIR rule could also affect the level of mercury co-benefits that are achieved.

set, then mercury banking should not be allowed while Phase 1 applies. As part of Phase 1, UARG members would be willing to install and certify mercury monitoring equipment in 2008, and all units would perform continuous monitoring of mercury emissions using either mercury CEMS or Method 324 starting in 2009 as EPA proposed in the supplemental notice.²⁸² This early mercury monitoring would provide EPA and the public with detailed information about the actual mercury emissions from each coal-fired unit.

Phase 2 of the proposed cap-and-trade program would begin in 2015. A nationwide mercury cap of 24 tons per year would apply. The mercury trading program would begin that year and mercury allowances would be allocated. Allowances would be based on heat input using heat input factors of 1.0 for bituminous units, 1.5 for subbituminous units, and 3.0 for lignite units.²⁸³ In 2018, Phase 3 of the program would begin and the mercury cap would be reduced to 15 tons per year.²⁸⁴ The mercury trading program would continue as under Phase 2.

²⁸² This monitoring commitment is supported by a substantial majority of UARG members. Some UARG members may present different views in their individual comments.

²⁸³ These mercury heat input adjustment factors are supported by a substantial majority of UARG members. One rationale for these factors is described in the attached technical comments of RMB Consulting. *See* RMB Technical Comments (Attachment 6).

Some UARG members believe that other adjustment factors should be used. They will present their views in their individual comments.

²⁸⁴ EPRI has examined the potential health effects of mercury emissions from an individual power plant using a probabilistic approach that took into account the uncertainties and variability associated with the fate and transport of mercury in the environment. *See* EPRI Comments at 29-32. That modeling produced distributions of exposure for several emission scenarios. EPRI's 2004 base case, which used estimated mercury emissions from 1999, predicted that only 0.6% of residents living within 50 kilometers of the plant would have exposures exceeding EPA's reference dose for methylmercury. Under a 15-ton cap-and-trade scenario, the percentage of residents exposed above EPA's RfD would drop by more than an order of magnitude from an already very low 0.6% to 0.04%. EPRI's work demonstrates that a 15-ton cap will be protective of public health.

A 15-ton cap will require an average 80% removal of mercury by *every* coal-fired power plant in the United States -- 15 tons of mercury emissions compared to 75 tons of mercury
(continued...)

UARG believes that this alternative cap-and-trade approach has a number of advantages over the one proposed by EPA. This approach accurately addresses the level of co-benefits in 2010 by not setting a numeric cap. It significantly reduces the amount of banking that can occur prior to 2018 by not allowing banking between 2010 and 2015 and by starting the banking program at a much lower level of mercury emissions than EPA. As a result, actual coal-fired power plant mercury emissions in 2018 are likely to be very close to 15 tons. The approach also achieves greater overall mercury reductions than EPA's proposal. Under EPA's proposal, EPA would distribute 34 tons of mercury allowances from 2010 to 2018 for a total of 272 tons of allowances.²⁸⁵ By contrast, under the alternative proposal, only an equivalent of 242 tons of mercury emissions would be allowed between 2010 and 2018.²⁸⁶ Given these advantages, EPA should adopt the proposed alternative cap-and-trade program.

The remainder of the comments in this section discuss EPA's cap-and-trade proposal, UARG's suggestions for implementation of a cap-and-trade program, and monitoring and compliance issues raised by EPA's cap-and-trade proposal.

A. EPA's Cap-and-Trade Proposal

EPA has proposed a cap-and-trade program to regulate mercury emissions from coal-fired power plants pursuant to its legal authority under § 111 or § 112(n)(1)(A) of the CAA.

entering power plants in the coal. To reach this nationwide level of annual mercury removal, 20% or more of all units will need to achieve 90% control. *See* Cichanowicz Technical Comments, Section 8. EPA has acknowledged that this level of control has yet to be commercially demonstrated. *See* 69 Fed. Reg. 12402. Utilities will need to develop new technologies to reach the 15-ton mercury cap.

²⁸⁵ 34 tons/yr * 8 yr = 272 tons.

²⁸⁶ Under the alternative proposal, there would be no mercury allocations between 2010 and 2015. For purposes of this estimate, actual emissions are assumed to be 34 tons per year -- EPA's current estimate of mercury co-benefits. Thus, emissions from 2010 to 2018 would be: (34 tons/yr * 5 yrs) + (24 tons/yr * 3 yrs) = 242 tons.

UARG agrees that EPA has legal authority to promulgate a cap-and-trade program under either § 111 or § 112. Based on its analysis of the proposed rule, UARG believes that EPA's proposal for a cap-and-trade program under § 112(n)(1)(A) has practical advantages over a similar program promulgated under § 111. A nationwide cap-and-trade program under § 112(n)(1)(A) would create a more efficient regulatory structure than a similar program under § 111(d), which, under EPA's interpretation, could result in a patchwork system that may vary from one state to the next.²⁸⁷

1. Application of EPA's December 2000 Listing Decision

On January 30, 2004, EPA proposed two separate alternatives for regulating mercury emissions from coal-fired power plants.²⁸⁸ First, EPA proposed setting national emission standards for HAPs pursuant to § 112 of the CAA through traditional MACT standards. This action would carry out EPA's December 2000 listing decision, which found, under § 112(n)(1)(A), that the regulation of electric utilities was "appropriate and necessary" and listed power plants as a major source category under § 112(c).

As a second alternative, EPA proposed establishing a cap-and-trade program pursuant to two separate legal authorities -- § 112(n)(1)(A) and § 111. Section 112(n)(1)(A) expressly calls for EPA to develop "alternative control strategies" to address HAP emissions from power plants that may warrant regulation under § 112. Under this approach, EPA would leave the essence of its December 2000 "appropriate and necessary" finding in place, but remove power plants from the § 112(c) list because if power plants remain on the § 112(c) list they must be regulated by

²⁸⁷ As discussed below, however, EPA should reexamine its interpretation of § 111(d) as it would apply to a mercury trading program and conclude that a patchwork approach would be precluded.

²⁸⁸ See 69 Fed. Reg. at 4652.

MACT standards under § 112(d).²⁸⁹ By removing power plants from the § 112(c) list, EPA can regulate mercury emissions from power plants using a proposed cap-and-trade program under § 112(n)(1)(A).

An analysis of what type of regulation is “appropriate and necessary” to address EPA’s identified mercury health concerns should include some form of cost-benefit analysis. Several documents submitted on the record from the Office of Management and Budget (“OMB”) during the Clinton Administration demonstrate that OMB believes that determinations regarding electric utilities should consider the likely benefits and costs of various regulatory approaches.²⁹⁰ In the preamble, EPA stated that “[w]e believe that . . . a ‘cap and trade’ approach to limiting [mercury] emissions is the most cost effective way to achieve reductions in [mercury] emissions from the power sector that are needed to protect human health and the environment.”²⁹¹ EPA later states

²⁸⁹ Section 112(c)(2) states that the EPA Administrator “shall establish emissions standards under subsection [112]d” for each of the listed source categories. CAA § 112(c)(2), 42 U.S.C. § 7412(c)(2); *see also id.* § 112(c)(5), 42 U.S.C. § 7412(c)(5) (EPA Administrator shall promulgate emissions standards under § 112(d) for source categories added to the § 112(c) list after 1991). Section 112(d)(2) in turn states that the emissions standards to be promulgated be MACT standards: EPA “shall require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section . . . that the Administrator determines is achievable” *Id.* § 112(d)(2), 42 U.S.C. § 7412(d)(2).

²⁹⁰ Memorandum from Art Fraas and Troy Miller, Office of Management and Budget, to Bill Maxwell (Sept. 24 1996) (Docket No. A-92-55, Item I-H-34) (“In addition, we believe that any determination on whether to regulate electric utilities should be made as a separate regulatory determination in accordance with the Administrative Procedures Act, taking into consideration both the likely benefits and costs of various regulatory (and non-regulatory) approaches. Should the Administrator decide that regulatory action is appropriate and necessary, development of alternative control strategies should also include a consideration of the incremental costs and benefits of each approach. . . .”); Memorandum from Art Fraas and Troy Miller, Office of Management and Budget, to Bill Maxwell (Sept. 12, 1996) (Docket A-92-55, Item I-H-24) (stating that EPA’s determination on whether to regulate HAPs from electric utilities should be made as a separate regulatory determination in accordance with the Administrative Procedure Act, taking into consideration both the likely benefits and costs of various regulatory and non-regulatory approaches).

²⁹¹ 69 Fed. Reg. at 4652.

that “the authorization to trade allows implementation of the emissions cap in the most cost-effective manner. Thus, the cap provides health protection by limiting overall emissions, but in a cost-effective manner.”²⁹² Since past experience and modeling by EPA and EPRI²⁹³ show that a cap-and-trade program is significantly more cost effective than a MACT approach, UARG believes that a cap-and-trade program better fits the “appropriate and necessary” standard.

EPA’s second legal authority for a cap-and-trade program is § 111. The two relevant provisions of § 111 are § 111(b), which applies to new sources,²⁹⁴ and § 111(d), which applies to existing sources.²⁹⁵ EPA’s proposal would include unit-specific mercury standards to regulate mercury emitted from new and modified power plants under § 111(b). Mercury from existing fossil fueled power plants would be regulated in a cap-and-trade program under § 111(d), which authorizes EPA to promulgate “standards of performance” that states must include in a plan applicable to mercury.

The § 111 cap-and-trade proposal would require a reversal of EPA’s December 2000 regulatory finding. EPA continues to believe that regulation of mercury is “appropriate;” however, EPA now believes that its 2000 regulatory finding hinged on the determination that § 112 was the only section of the CAA that could adequately address the health hazards associated with mercury emissions.²⁹⁶ EPA now proposes to conclude that hazards to the public

²⁹² 69 Fed. Reg. at 4686.

²⁹³ See EPRI Comments, Appendix B.2.

²⁹⁴ A “new source” is defined as “any stationary source, the construction or modification of which” begins after the proposed NSPS covering that type of source is published. CAA § 111(a)(2), 42 U.S.C. § 7411(a)(2).

²⁹⁵ “Existing source” means any stationary source other than a new source. *Id.* § 111(a)(6), 42 U.S.C. § 7411(a)(6).

²⁹⁶ See 69 Fed. Reg. at 4683.

health can be adequately addressed by § 111, and, hence, that regulation is not “necessary” under § 112.²⁹⁷ EPA has also stated (and UARG agrees) that it does not believe it needs to go through a formal delisting procedure to reverse its December 2000 finding.²⁹⁸

2. EPA’s Proposed Cap-and-Trade Program Under § 111

UARG believes that EPA’s explanation of its legal authority to propose a cap-and-trade program under § 111 of the CAA is reasonable.²⁹⁹ The § 111 program requires analysis of two prongs -- first, does EPA have authority under § 111 to regulate HAPs that are listed under § 112(b)(1); and second, does a cap-and-trade program fit within the § 111(a)(1) definition of a “standard of performance”?

Because nothing in the legislative history suggests that Congress intended EPA to regulate HAPs exclusively under § 112, § 111 is a viable and appropriate statutory authority by which to regulate mercury emissions. Section 111(d) provides EPA with the authority to

²⁹⁷ *See id.*

²⁹⁸ As discussed above, UARG filed an action in the U.S. Court of Appeals for the D.C. Circuit challenging EPA’s listing decision. EPA successfully argued to the court that UARG’s action should be dismissed because EPA’s listing decision was not final agency action. Since that decision was not a final agency action, the Administrative Procedure Act does not require EPA to go through a formal delisting to reverse that decision.

²⁹⁹ EPA states that it is establishing a subpart Da NSPS. It appears that EPA intends for its proposed rule to affect all facilities capable of producing more than 25 megawatts (“MW”). However, the subpart Da NSPS currently applies to utility units capable of firing more than 73 MW heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. *See* 40 C.F.R. § 60.40a(a). Section 112 defines “electric utility steam generating unit” as “any fossil fuel fired combustion unit of more than 25 megawatts that serves as a generator that produces electricity for sale.” *See* CAA § 112(a)(8), 42 U.S.C. § 7412(a)(8). An industrial cogeneration facility is defined under CAA § 112 as a facility that “supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system. . . .” *See id.* § 112(a)(8), 42 U.S.C. § 7412(a)(8). Accordingly, if EPA proceeds with a final cap-and-trade rule under § 111, it will need to clarify the definition of covered facilities in subpart Da.

promulgate “standards of performance” that states must include in plans applicable to those sources.

EPA notes that two different and conflicting amendments to § 111(d) were enacted in the 1990 Amendments to the CAA.³⁰⁰ The differences between the two amendments, which are contained in the Statutes at Large, are reflected in parentheses as follows:

The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) *(or emitted from a source category which is regulated under section 112)*^[301] *(or 112(b))*^[302], but (ii) to which a standard of performance under this section would apply if such existing source were a new source. . . .

CAA § 111(d)(1) (emphasis and language of amendments supplied).³⁰³ The Conference Report that accompanied S. 1630 (the 1990 CAA Amendments) includes two independent and conflicting changes to § 111.³⁰⁴ The legislative history reveals that the first version appears in the House bill, which inserts the phrase “or emitted from a source category which is regulated under section 112.”³⁰⁵ The second change appears in the bill passed by the Senate that inserts

³⁰⁰ See 69 Fed. Reg. at 4685.

³⁰¹ Pub. L. No. 101-549, § 108(g), 104 Stat. 2467 (1990).

³⁰² *Id.* § 302(a), 104 Stat. 2574.

³⁰³ The Statutes at Large constitute the legal evidence of the laws, where, as here, Title 42 of the United States Code, containing the CAA, has not been enacted into positive law. See 1 U.S.C. § 204(a); *United States v. Welden*, 377 U.S. 95, 98 n.4 (1964); *Washington-Dulles Transportation Ltd. v. Metropolitan Washington Airports Auth.*, 263 F.3d 371, 378 (4th Cir. 2001) (the Statutes at Large are “legal evidence” of the law).

³⁰⁴ H.R. Conf. Rep. No. 101-952, at 73, 1633 (1990).

³⁰⁵ Pub. L. 101-549, § 108(g). Under the House language, a standard of performance under § 111(d) cannot be established for any air pollutant that is emitted from a source category

(continued...)

“112(b).”³⁰⁶ The Conference Report provides no explanation or reconciliation of these conflicting changes, which essentially provide different standards as to the scope of EPA’s authority to regulate under § 111(d) and, thus, affect whether EPA has the authority to regulate § 112-listed HAPs under § 111.

Where there are conflicting provisions in a statute, a federal agency must try to harmonize the conflicting provisions and adopt a reading that gives some effect to both provisions.³⁰⁷ EPA harmonizes the differing language as follows: “Where a source category is being regulated under § 112, a § 111(d) standard of performance cannot be established to address any HAP listed under § 112(b) that may be emitted from that particular source category.”³⁰⁸ The effect of this interpretation is that if EPA is regulating a source category under § 112, § 111(d) could not be used to regulate emissions of § 112-listed pollutants from that particular source category. As a result, in order to propose a cap-and-trade program under § 111(d), EPA has proposed reversing its December 2000 regulatory finding to remove electric utility steam generating units from any regulation under § 112. UARG believes that EPA’s reconciliation of the differing language is reasonable and legally supportable.

A second issue involves whether a cap-and-trade system fits within the definition of “standard of performance” under § 111(a)(1). “Standards of performance” are intended to reflect

regulated under § 112. Thus, EPA could not regulate HAP and non-HAP emissions that are emitted from a source category regulated under § 112.

³⁰⁶ *Id.* § 302(a). Under the Senate language, a standard of performance under § 111(d) cannot be established for any HAP that is listed in section 112(b), regardless of what categories of sources of that pollutant are regulated under § 112.

³⁰⁷ *See, e.g., Citizens to Save Spencer County v. EPA*, 600 F.2d 844 (D.C. Cir. 1979) (interpreting conflicting amendments under the CAA). In this case, due to the absence of any legislative history directly on point, EPA has focused on the plain language.

³⁰⁸ 69 Fed. Reg. at 4685.

the “degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.”

EPA interprets the term “standard of performance,” as applied to existing sources, to include cap-and-trade programs. The legislative history does not address specifically whether an allowance or trading program was intended under the term “standard of performance.” Congress’s intent, however, was that existing sources be accorded flexibility in meeting regulatory standards, and therefore, it is reasonable to interpret this legislative history as supporting the use of cap-and-trade programs.³⁰⁹ The House Report accompanying the proposed 1977 CAA Amendments stated that, for standards under § 111(d), the Administrator would establish guidelines defining the best system for each category of existing source, and states would then be responsible for determining the applicability of such guidelines to any particular source or sources.³¹⁰

Moreover, § 111 “standards of performance” must reflect the degree of emission limitation achievable through application of “the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.”³¹¹ EPA proposes to determine that a cap-and-trade program is the

³⁰⁹ *See id.* at 4697.

³¹⁰ H.R. Rep. No. 95-294, at 195, *reprinted in A Legislative History of the Clean Air Act Amendments of 1977*, Vol. 4, at 2662 (1978).

³¹¹ CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1).

best system for reducing mercury emissions from power plants.³¹² EPA also plans to evaluate the emission levels, health risks, and available control mechanisms to confirm whether the cap-and-trade program, as implemented, constitutes the “best system” of emissions reductions.³¹³

As stated above, UARG believes that EPA’s explanation of its legal authority to propose a cap-and-trade program under § 111 of the CAA is reasonable. UARG disagrees with EPA’s proposal, however, to allow states to decide not to participate in a § 111 trading program. In this case, the EPA Administrator has made a regulatory determination under § 111 “that a cap-and-trade program has been adequately determined to be *the best system* for reducing [mercury] emissions from coal-fired Utility Units”³¹⁴ after “taking into account the cost of achieving such reduction.” The system the Administrator proposes to determine is “the best system,” considering costs, is a nationwide interstate cap-and-trade program for mercury, with mercury allowances fully allocated at the levels authorized by the Administrator and with full and unrestricted participation by affected sources in all 50 states.

Although states have authority under § 111(d) to structure plans for implementing or “applying”³¹⁵ a standard of performance in a § 111 trading program,³¹⁶ those state plans must be consistent with EPA’s regulatory determination. EPA cannot, for example, permit states to “opt out” of that trading program. Once EPA makes the determination, as it proposes to do here, that an interstate cap-and-trade program with unrestricted trading and full allocation of allowances is

³¹² *Id.* at 4697.

³¹³ *Id.* at 4686-87.

³¹⁴ 69 Fed. Reg. at 4697 (emphasis added).

³¹⁵ CAA § 111(d), 42 U.S.C. § 7411(d).

³¹⁶ For example, states retain authority to determine how to allocate allowances to sources within the state, provided the states allocate the full amount of allowances allotted to them under EPA’s regulatory determination.

the best system for reducing mercury emissions from coal-fired power plants, states cannot interfere with that determination by refusing to participate fully in that program. As stated above, the legislative history for § 111 shows that Congress intended for the EPA Administrator to establish guidelines as to what the best system for each category of existing sources is -- in this case, an interstate cap-and-trade program. Nothing in the Act or the legislative history gives states the ability to choose not to follow the guidelines that EPA establishes under § 111 based on the Administrator's "best system" determination.

Section 111(a) makes clear that it is the EPA Administrator that determines what the standard of performance shall be. Section 111(a)(1) states that the standard of performance is the standard that "*the Administrator determines has been adequately demonstrated*" (emphasis supplied). "Standard of performance" is defined in § 111(a) "[f]or purposes of this section" -- *i.e.*, all of § 111, including § 111(d) as well as § 111(d). Thus, only the EPA Administrator, not states, can determine standards of performance under § 111(d).

A decision by EPA to permit states to opt out of a cap-and-trade program established under § 111 would threaten to create a patchwork approach that would affect -- and change -- the EPA-determined standard of performance for emission reduction of mercury from electric utility steam generating units. EPA's determination that a cap-and-trade program is the best system included an analysis by EPA of the costs involved -- as is required by § 111(a)(1). EPA's cost estimates were premised on the establishment of a cap-and-trade program in all 50 states, without any state-imposed limits on allocation of allowances and without restrictions on the trading of allowances among affected units within states and across state lines. Nonparticipation by some states in the cap-and-trade program would be incompatible with EPA's determination of

the appropriate level of control costs,³¹⁷ not only for sources in those states but also for sources in other states, which would have a smaller number of allowances available to them on the market.

For the same reason, EPA cannot permit states to decline to issue all the allowances available within the state under EPA's regulatory determination. To allow a state to decide to refuse to allocate all available allowances would effectively permit that state to modify the result of EPA's regulatory determination, including its consideration of the appropriate level of control costs. For example, in the Supplemental Notice, EPA proposes to cap mercury emissions from electric utility steam generating units in Pennsylvania at 0.710 tons per year beginning in 2018.³¹⁸ This means that Pennsylvania will have 22,720 allowances available for distribution to electric utility steam generating units located within its borders.³¹⁹ If Pennsylvania decided to allocate to Pennsylvania units only one-half the number of allowances authorized by EPA (*i.e.*, 11,360 allowances),³²⁰ the nationwide cap -- which represents the EPA-determined best system of emission reduction -- would be tightened by 0.335 ton. That would make compliance more costly than EPA determined was appropriate, not just in Pennsylvania but nationwide. Section 111(a)(1) provides that EPA is to set a standard of performance. Thus, although a state has authority to determine how to allocate mercury allowances to sources within its borders (*e.g.*, by

³¹⁷ *See, e.g.*, 69 Fed. Reg. at 4703 (noting that “[s]tates that elect to participate in the trading program . . . are expected to see substantially lower compliance costs for their sources. . . .”).

³¹⁸ 69 Fed. Reg. at 12445.

³¹⁹ Each allowance will permit one ounce of mercury emissions. *Id.* at 12400. There are 32,000 ounces in one ton.

³²⁰ *Id.* at 12407.

determining whether to have a permanent or an updated allocation),³²¹ it must be required to allocate *all* of the allowances available to the state.

In addition to having authority to determine how to allocate allowances (provided they allocate all available allowances), states may also “identify[] sources subject to the rule” and “issu[e] new or revised permits as appropriate,” as EPA proposes.³²² Providing states with authority over these types of issues does not result in a change in the nature or stringency of the standard of performance determined by the EPA Administrator. Any authority given to states, however, cannot fundamentally undermine the cap-and-trade program that EPA establishes under § 111 because that program reflects the Administrator’s “best system” determination under § 111(a)(1).

If its state law permits, a state presumably may have authority to impose a more stringent mercury emissions limitation on sources within its borders. That limitation would not be federally enforceable, however. A state’s imposition of more stringent limitations under state law presumably may result in sources within the state having extra § 111 mercury allowances that they would not need to cover their mercury emissions as a result of the more stringent limitations. Those sources could of course sell the allowances to sources in other states. States must be prohibited from restricting the ability of sources to sell or trade any mercury allowances issued under a § 111 trading program, including any allowances made available as a result of stricter state emissions limitations.³²³

³²¹ This is an example of a state choice regarding how to “apply []” a § 111(d) standard of performance within the state’s borders.

³²² *Id.* at 12413.

³²³ *See also* section VI.B.9, *infra*.

In sum, UARG agrees with EPA's proposed determination that an interstate cap-and-trade program provides the "best system" of mercury reduction for electric utility steam generating units. EPA is administering cap-and-trade systems successfully in the Acid Rain program and the NO_x SIP Call rulemaking. These programs have demonstrated that a cap-and-trade system provides industry with the flexibility to comply with national emission levels in a cost-effective manner. UARG supports EPA's cap-and-trade proposal under § 111, provided EPA makes it clear that states do not have authority to decide not to participate in the interstate trading program and do not have authority to refuse to allocate all available allowances to their affected sources. It is UARG's opinion, however, that EPA's proposed rule under § 112(n)(1)(A) provides a stronger basis upon which to promulgate a cap-and-trade program.

3. EPA's Cap-and-Trade Program Under § 112(n)(1)(A)

As previously discussed in these comments, § 112(n)(1)(A) provides the Agency with broad authority to craft regulations to address any public health concerns it identifies. Section 112(n)(1)(A) does not require EPA to regulate under § 112(c) and (d). Instead, the provision states broadly that EPA shall regulate *under this section* if the Administrator finds that regulation is appropriate and necessary. EPA could establish regulations under § 112(n)(1)(A) itself, or the MACT provisions of § 112(d), or the risk-based provisions of § 112(f) and satisfy the § 112(n)(1)(A) authorization to regulate "under this section."

The best reading of § 112(n)(1)(A) is that Congress intended EPA to consider a variety of control options to address whatever health concerns were identified in the Utility Study to Congress and then to promulgate rules based on the best of those options. Indeed, the limited legislative history of § 112(n)(1)(A) supports a broad grant of authority. This legislative history indicates that EPA has broad discretion to establish regulatory standards, should it find such standards necessary to protect public health. As discussed in these comments, the choice of the

House language over the Senate language demonstrates that the Administrator is not constrained to set a MACT standard under § 112(d). The Senate language, which included a direct reference to that subsection, was replaced with House language that speaks generally of regulation under § 112. Representative Oxley's comments further suggest that the only plants that should be regulated under § 112(n)(1)(A) are those with respect to which a significant risk to human health has been demonstrated.

UARG believes that EPA's proposed cap-and-trade program pursuant to its legal authority under § 112(n)(1)(A) is superior to the § 111 program because § 111 programs are implemented by the states, rather than the Federal government, creating the need for additional procedural and administrative steps to implement the trading program. In other words, establishment of a cap-and-trade program under § 111 would create a legal mechanism that would require each state to conduct rulemakings before full implementation of the trading program could occur.

A program implemented under § 112 will be a federal program, with one national procedure. Federal cap-and-trade programs have proven successful in the past. For example, the Acid Rain Program, a national cap-and-trade program covering SO₂ emissions from utilities, has successfully resulted in a 41% reduction in SO₂ emissions from 1980 through 2002 (despite a significant increase in electrical generation).³²⁴ And, despite some claims that the Acid Rain Program would result in "hot spots," there is no evidence that it has.³²⁵ Thus, it is clear that a cap-and-trade program can successfully reduce emissions without creating "hot spots." This is

³²⁴ 69 Fed. Reg. at 4697.

³²⁵ See Section VI.B.1.

not surprising because, in a free-market trading program, the largest emitters generally are the ones that find it most economically beneficial to reduce emissions.

B. UARG’s Suggestions for Implementation of a Federal Cap-and-Trade Approach To Regulate Mercury Emissions from Electric Utility Steam Generating Units

EPA states that a market-based cap-and-trade approach under § 111 or § 112 has advantages over regulation unit-by-unit or facility-by-facility pursuant to § 112 MACT standards. UARG agrees. Market-based approaches rely on economic forces to stimulate development and implementation of new technologies in ways that command-and-control emissions limits such as MACT limits often do not. If the new technology achieves substantial mercury reductions, a utility using that technology will have excess allowances that it can sell or use elsewhere in its system. If the new technology does not perform as well as expected, the unit can still purchase allowances to comply with its annual mercury limit. In contrast, under a MACT rule, utilities will be reluctant to install new technology because if it does not perform as expected, the unit would be in violation of the limit.³²⁶ A trading approach permits utilities to make more rational investments in emissions control. For these reasons, UARG supports EPA’s proposal for a market-based cap-and-trade program and believes that such a program promulgated under § 112 would provide more certainty and flexibility to industry and achieve emission reductions in a much more cost-effective way than traditional command-and-control programs such as MACT.

³²⁶ A MACT limit forces companies to make the “safe” decision to ensure they meet the limit.

1. A Mercury Cap-and-Trade Program Will Not Create “Hot Spots”

A recurring theme whenever a market-based trading program is proposed is that “hot spots” will be created. In the case of mercury, this claim has already been asserted by environmental groups, by senators and congressmen writing to EPA, and by many individual commenters. Their claims either presume that “hot spots” currently exist as a result of coal-fired power plant emissions or theorize that they will develop as a result of mercury trading. These commenters do not define the term “hot spot,” nor do they provide factual evidence demonstrating the actual existence of “hot spots,” nor do they offer plausible explanations of how “hot spots” would be created by a mercury trading program. The truth is there are no coal-fired power plant mercury “hot spots” in the United States and EPA’s proposed mercury cap-and-trade program will not create them.

There is no scientific definition of a “hot spot.” One possible interpretation of the term is an area having high, localized mercury deposition and much higher than normal health risks.³²⁷ A detailed literature review failed to produce evidence of measurements showing high levels of mercury deposition near coal-fired power plants. Likewise, there is no evidence in the rulemaking record of areas with high mercury deposition levels.³²⁸ Comments submitted by EPRI in this rulemaking reveal that the highest levels of mercury deposition in the U.S. are

³²⁷ See 69 Fed. Reg. at 4703. The preamble to EPA’s proposed rules offers a second interpretation of the term, namely “that a power plant may lead to a hot spot if the contribution of the plant’s emissions of Hg to local deposition is sufficient to cause blood Hg levels of highly exposed individuals near the plant to exceed the RfD.” *Id.* at 4702.

³²⁸ The National Atmospheric Deposition Program’s mercury deposition network (“MDN”) does not reveal any areas with unusually high mercury deposition. The vast majority of mercury wet deposition results in 2002 fell in a range of 8.0 to 19.5.1 ug/m². The limited variance in these air deposition measurements is hardly surprising since 70% of the mercury deposited in the United States comes from sources outside North America. See Comments of EPRI on the EPA Electric Utility Mercury Emissions Rule (June 16, 2004) (Docket No. OAR-2002-0056-2578).

primarily attributable to non-utility sources.³²⁹ Indeed, utilities contribute more than 50% of the mercury deposition in only 0.4% of the land area of the U.S. and those areas are not the areas where the highest deposition of mercury occurs.³³⁰

Several comments about mercury “hot spots” cite modeling work performed by EPA as a source of those claims. EPA’s mercury deposition modeling was done using the Regional Modeling System for Aerosols and Deposition (“REMSAD”) model, which is a regional grid model. As detailed work by EPRI shows, regional grid models overpredict local effects.³³¹ There are three basic reasons for these overpredictions: (1) regional models deposit mercury to the ground closer to the source than does a single-source plume model; (2) regional grid models do not include likely mercury reduction reactions in plumes, which tend to reduce nearby mercury deposition; and (3) regional air models can only be verified against limited wet deposition data at moderate values; they consistently overestimate wet and dry deposition in areas where higher deposition rates are calculated. EPRI’s work shows that regional air models can over predict total local mercury deposition by factors of 1.6 to 3.4 due to the first factor alone.³³²

One example of the problem with regional grid models is illustrative. EPA’s REMSAD model predicts that high levels of mercury deposition will occur in Pennsylvania as a result of coal-fired power plant emissions. Yet if one examines the methylmercury levels in fish in Pennsylvania, one finds that the average freshwater fish concentration is below the national

³²⁹ See EPRI Comments at 6.

³³⁰ See *id.* at 2.

³³¹ *Id.*

³³² See *id.* at 55-58.

average.³³³ This example supports the conclusion that EPA's regional model does not accurately predict local mercury deposition levels.³³⁴ EPRI modeling work using a single-source plume model reveals that only one percent of the gaseous ionic and elemental mercury emitted by coal-fired power plants deposits within 10 kilometers of the site.³³⁵ Thus, mercury emissions from coal-fired power plants are unlikely to be a significant contributor to high localized deposition.

Some commenters have suggested that a report released by the Florida Department of Environmental Protection in late 2003 demonstrates the existence of "hot spots." They also cite the report as showing how limiting mercury releases from industrial sources supposedly will cause rapid decreases in mercury concentrations in the environment. Neither conclusion follows from the Florida report. The sources of industrial mercury emissions in the Florida report are municipal and medical waste incinerators, not power plants. Incinerators produce far higher percentages of ionic mercury than do coal-fired power plants. That fact coupled with the much shorter stack heights of incinerators results in higher amounts of mercury being deposited near these sources. The modeling performed for the Florida study also has severe limitations that make the study's results unreliable. The modeling assumes that mercury deposition in waterways comes only from local sources. Yet modeling by EPA and EPRI has shown that more

³³³ The average fish concentration in Pennsylvania is 0.11 mg/kg while the national average is 0.22 mg/kg. *Id.* at 125

³³⁴ The atmospheric chemistry of mercury contained in EPA's REMSAD model may also contribute to overestimates of mercury deposition levels in Pennsylvania. When EPRI models were modified to include a surrogate for the conversion of ionic mercury to elemental mercury, the model performance improved -- the predicted mercury deposition in Pennsylvania decreased while deposition in other areas, such as Wisconsin, did not significantly change. *See* EPRI Comments at 18-19; Seigneur, C. Vijayaraghanan, K., Lohman, K., Karamchandani, P., and Scott, C., "Global source attribution for mercury deposition in the United States," *Environ. Sci. Technol.*, Vol. 38,555-69 (2004).

³³⁵ *See* EPRI Comments at 61.

than 60% of the mercury that deposits in Florida originates outside the United States. In addition, the modeling does not incorporate mercury reactions in the atmosphere, again causing local deposition to be overstated. Thus, the Florida study does not justify a conclusion that coal-fired power plants create local “hot spots.”

Similarly baseless are claims that the Florida study shows that mercury emission reductions are quickly reflected in decreased mercury levels in nearby waterbodies. First, mercury reductions were observed in less than half the sites studied in Florida. Thus, questions remain about why reductions were seen at some sites but not others. Second, the Florida Everglades, which are the subject of the Florida study, are a unique ecological system that is strikingly different from other U.S. waterways. The Everglades are in a tropical zone with no distinct seasons, the water is shallow, and the bottom sediments are very different from other locations. Other waterbodies also have different levels of acidity, biological activity, dissolved oxygen, and turbidity. All of these differences can dramatically affect mercury cycling and uptake by biological organisms and make extrapolation of the Florida results to other areas of the country inappropriate.³³⁶

Mercury “hot spots” will not be created by a cap-and-trade program. Cap-and-trade programs promote economically efficient decisions to reduce emissions from sources. Units with the highest mercury emissions almost certainly will be among the first to be controlled since the cost per pound of mercury controlled generally will be the lowest at these units. This

³³⁶ More detailed descriptions of the Florida results and how they have been misinterpreted can be found in the comments of the Florida Electric Power Coordinating Group and the Southern Company.

economic behavior has previously been demonstrated in utilities' compliance with EPA's Acid Rain requirements.³³⁷

In addition, EPA has structured its proposed CAIR and mercury cap-and-trade rules in a way that likely will cause larger reductions in the already small amounts of nearby mercury deposition as Phase I of CAIR is implemented. The forms of mercury that have the greatest potential to deposit near coal-fired power plants are particulate-bound mercury and gaseous ionic mercury. These forms of mercury are controlled by wet or dry scrubbers. Thus, the addition of scrubbers to meet CAIR requirements will produce a co-benefit of reducing currently small levels of nearby deposition.

Modeling performed by EPRI shows that mercury deposition will not increase in any area as a result of a cap-and-trade program.³³⁸ This result makes sense when one recognizes that, in the aggregate, all coal-fired electric utility steam generating units will need to achieve an average mercury removal efficiency of 80% to meet the proposed 2018 cap of 15 tons.³³⁹ Current mercury emission testing shows that it will be difficult to achieve 80% control at an individual unit, much less across the entire industry. Mercury control levels more stringent than 80% are problematic and uncertain given the large variations in mercury emissions from coal-fired units and the absence of commercially available mercury-specific control equipment. As a result,

³³⁷ See, e.g., Swift, Allowance Trading and Potential Hot Spots -- Good News from the Acid Rain Program, *Environment Reporter*, Vol. 31, No. 19, at 954-959 (May 12, 2002).

³³⁸ See EPRI Comments at 6-11. EPRI modeling shows that areas where utility emissions dominate deposition will not increase under a cap-and-trade rule. Rather the areas where utility emissions dominate will be reduced from 0.4% less than one-tenth of that amount. See EPRI Comments at 11, Figure A.1-3.

³³⁹ EPA and UARG have estimated from the Part 2 ICR data that approximately 75 tons of mercury was contained in the coal burned by power plants in 1999. The 2018 cap of 15 tons requires an 80% removal of mercury from this input amount.

there will not be a large market of mercury allowances, and an individual unit will not be able to enter the market and purchase large numbers of mercury allowances that would allow it to increase emissions.

2. Calculation of the Baseline for Allowance Allocations

EPA proposes to calculate the baseline heat input by “using the average of the three highest heat inputs of the period 1998 to 2002.”³⁴⁰ Although this historical baseline approach has the benefit of avoiding the possibility that units will attempt to affect the baseline through actions such as fuel switching, it does have a problem in that the heat input data will be outdated by the time the trading programs begins. As an alternative, UARG suggests using the average of the three highest heat inputs of the period 1999 to 2003; this approach would use a period that would be closer in time to the commencement of the trading program, begins while avoiding opportunities to affect the baseline through prospective actions.

In addition, EPA must take steps to ensure that the heat input data for non-Title IV units are accurate. In its proposal, some of the heat input data that EPA provides for non-Title IV units are incorrect. It is important that the heat input data for these units be correct so that accurate baselines can be established.

3. The Cap-and-Trade Program Should Have Permanent Allocations with a Set Aside for New Sources

UARG supports a cap-and-trade program with permanent allocations of mercury allowances. Permanent allocations provide units with certainty regarding their allowances, which aids in compliance planning. Permanent allocations also provide units with an incentive to improve energy efficiency and require fewer resources to administer as compared to an

³⁴⁰ 69 Fed. Reg. at 4703. EPA then would adjust this baseline heat input using the adjustment factors discussed above in section VI.

updated allocation system. UARG believes a permanent allocation approach provides a less complicated method for allocating allowances while providing the greatest amount of certainty to units.

Permanent allocation systems can have the disadvantage of possibly impeding new units from entering service. New units that begin service after the start of the trading program will still need to comply with the cap-and-trade program by surrendering one allowance for each ounce of mercury emissions; however, under a strict permanent allocation system, new sources do not receive an allowance allocation. UARG suggests that the permanent allocation system coupled with a set aside of two percent of allowances for new sources.

4. Auctions

UARG strongly opposes permitting states to decide, under a § 111 cap-and-trade program, to hold an auction to sell allowances to the highest bidders (or any other method of forced sale of allowances). States do not have the authority under § 111 to decide to sell allowances at auction, rather than simply allocating them to sources within their borders, because doing so would result in a fundamental change in the standard of performance set by EPA.³⁴¹ As discussed above, states have authority, in applying the EPA-determined standard of performance, to make decisions with regard to some elements of a § 111 cap-and-trade program, such as the specific allowance allocation formula for individual units or sources; however, states do not have authority under the Act to make decisions that will result in a change in the stringency of the EPA-determined standard of performance. If states are permitted to sell allowances at an auction (or otherwise) rather than allocate them without charge, this will substantially change the cost

³⁴¹ See Section VI.A.2. *supra*.

analysis for the standard of performance that EPA conducted, and thus change the standard itself. States do not have that authority.

Moreover, a program that sells allowances, rather than distributes them without charge to sources, results in a situation where those sources pay for the right to emit even the tons that are *under* the cap. This is completely counter to the principle that regulated sources should pay only to control emissions *down to* the cap. Auctioning allowances rather than distributing them without charge vastly increases the program's cost beyond the point of cost effectiveness, undermining EPA's "standard of performance" determination.

For similar reasons of preserving the cost-effectiveness of the trading program, EPA under a § 112(n)(1)(A) cap-and-trade program should not have allowance auctions but should distribute allowances without charge. If EPA does conduct auctions, they should be only for a very small percentage of allowances each year, as EPA does in the auction program in the Title IV Acid Rain Program. Any auction program for mercury should be patterned after the Title IV program and be similarly limited in scope. In addition, as in the Title IV program, any proceeds from allowance auctions should not be deposited in the general revenues under the Miscellaneous Receipts Act but should instead be redistributed to compliance account holders on a proportional basis.

5. Safety Valve

UARG generally supports EPA's proposal to have a safety valve provision for the mercury cap-and-trade program. Under EPA's proposed safety valve mechanism, future-year allowances could be "borrowed," and used in earlier years, at a cost of \$2,187.50 per allowance³⁴² (covering one ounce of mercury emissions). This approach provides units with

³⁴² This figure would be adjusted annually for inflation.

additional flexibility, particularly in the early years of the program when technology may not be fully implemented. EPA should, however, modify its proposed safety valve mechanism.

EPA suggests that the safety valve mechanism works best with an updated allowance allocation system. UARG disagrees. In EPA's proposal, allowances borrowed from future years would be removed from the general pool of allowances available to all units within the state. This would result in fewer allowances available for allocation in future years not only to the units that borrowed allowances but to *all* units. This method would produce unfair results because units that did not borrow future allowances would bear part of the burden of a reduced number of allowances in future years.

UARG believes that the safety valve mechanism in fact works best with a permanent allocation system. Instead of borrowing from the general pool of allowances, a unit could borrow its own future-year allowances, resulting in fewer allowances available to *that unit* in future years. The unit would still pay EPA the price of \$2,187.50 per allowance for the privilege to borrow against future years.

If EPA does decide to use an updated allocation system, then UARG suggests that EPA structure the safety valve mechanism so that a unit would borrow from future years of allowances already allocated to that unit. For example, in EPA's proposed updated allocation approach, units always have a five-year supply of allowances allocated to them; under that approach, EPA should permit units to borrow only from the future allowances already in their unit accounts.

EPA also proposes that funds received from the purchase of safety valve allowances be deposited in the U.S. Treasury. UARG suggests that these funds instead be provided to the U.S.

Department of Energy to assist in the development of innovative mercury emissions control projects.

6. Any Cap-and-Trade Program Should Permit Banking of Allowances Without Restriction

UARG supports EPA's proposal to allow banking of allowances without restriction after the start of the cap-and-trade program. Banking rewards sources for creating emission reductions beyond required levels by allowing the source to bank any unused allowances for use later. Banking creates strong environmental benefits by encouraging sources to reduce their emissions earlier and in greater amounts. In addition, UARG's proposal that the cap-and-trade program not begin until Phase 2 of the program in 2015 further addresses any concern that some may have regarding the potential effects of banking in allowing higher emissions in later years.

7. Early Reduction Credit Program

UARG supports the creation of an early reduction credit feature as part of the mercury trading program to aid in the development of mercury emissions control technologies. EPA should create a small reserve of early reduction credits for units that install mercury-specific control technology by 2014. EPA should limit the program to mercury-specific controls; no credits should be given for the installation of scrubbers, SCRs, or other controls designed primarily to reduce emissions of NO_x, SO₂, or other non-mercury emissions. EPA should award credits only for reductions of mercury emissions that result from mercury-specific controls that go beyond the reductions achieved as co-benefits from NO_x or SO₂ controls. This type of program will provide companies with an incentive to invest in innovative technologies and will stimulate the development of new mercury-specific controls.

8. Units Emitting Less Than 25 Pounds of Mercury Per Year Should Be Excluded from the Cap-and-Trade Program

EPA expresses concern in its proposal that mercury-specific control technologies under development will not be practical to apply to sources that emit less than 25 pounds of mercury per year.³⁴³ UARG agrees that this could present a problem for those units and supports a provision excluding those units from the cap-and-trade program, provided that the overall cap on mercury emissions is not reduced by the small amounts that these sources emit (*e.g.*, the 2018 cap should remain (allocated on a heat input basis) 15 tons even if these sources are excluded from the program).

9. EPA Must Prohibit State Interference with the Cap-and-Trade Program

EPA must make clear that states cannot interfere with the cap-and-trade program. For example, states should be expressly prohibited from requiring units to surrender more allowances than required by EPA's one-allowance-per-ounce rule or from placing restrictions on the intrastate or interstate transfer of allowances. As discussed above, the CAA prohibits state interference with the fundamental aspects of a cap-and-trade program under § 111, *e.g.*, those aspects that affect the program's overall stringency and costs.³⁴⁴ EPA also must prohibit interference with a national cap-and-trade program under § 112 so that the cap on mercury emissions that EPA establishes cannot be changed by states. For example, a state requirement that sources within the state surrender two allowances for every ounce of mercury emissions would make the EPA-established nationwide cap on mercury emissions more stringent -- and compliance with that cap more expensive. That result would be fundamentally inconsistent with EPA's regulatory determinations in establishing the program. EPA needs to make clear in the

³⁴³ 69 Fed. Reg. at 4699.

³⁴⁴ *See* Section VI.A.2.

final rule that this type of state regulation (and any action by a state that would have this effect) is prohibited. Similarly, any attempt by a state to place restrictions on the sale of mercury allowances by its sources (such as prohibiting sales to certain other states) would fundamentally change the EPA-established trading program and its cost basis and would be contrary to EPA's regulatory determinations. UARG, therefore, urges EPA to include provisions in its rules that expressly prohibit states from interfering with the cap-and-trade program in the ways described above or in any other way.

10. One Allowance Should Permit a Source To Emit One Ounce of Mercury Anywhere in the United States

EPA should not require units in “sensitive” areas to surrender more allowances than units in other areas deemed less “sensitive” (*e.g.*, requiring some units to surrender two allowances for each ounce of mercury emissions rather than the standard one allowance per ounce).³⁴⁵ Hot spots have not resulted in the Title IV Acid Rain Program, and, as discussed above,³⁴⁶ no reason exists to believe they will occur in this program. Moreover, requiring different areas to surrender different numbers of allowances would complicate the trading program and result in a lowering of the cap, contrary to EPA's regulatory determinations.

11. Compliance on Facility-Wide Basis

EPA proposes to require compliance under the mercury cap-and-trade program on a facility-wide basis rather than on a unit-by-unit basis as it did in the original Title IV Acid Rain Program trading rules. Under this approach, instead of each individual unit having a unit account, each facility would have a “compliance” account, which would need to hold allowances

³⁴⁵ 69 Fed. Reg. at 4701.

³⁴⁶ See Section VI.B.1.

(as of the allowance transfer deadline) in an amount at least equal to all mercury emissions from the entire facility in the preceding calendar year. UARG does not object to EPA's proposal to require compliance on a facility-wide basis rather than on a unit-by-unit basis.

12. Miscellaneous Implementation Issues

As a general matter, UARG suggests that EPA pattern the mercury cap-and-trade program on the Title IV Acid Rain Program. In that regard, EPA, as it does in the Title IV program, should not require Title V operating permits to be reopened or revised for allocation, transfer, or deduction of allowances. In addition, EPA should assign serial numbers to mercury allowances. Although tracking and reporting serial numbers does result in some administrative burden, that burden is significantly outweighed by the benefits that serial numbers provide for tax and accounting purposes for regulated companies and other market participants.

C. Monitoring and Compliance Issues

1. EPA's Proposed Compliance Methods

To determine compliance with allowance holding requirements under the proposed cap-and-trade program, EPA proposes to add provisions for mercury mass emissions monitoring to the existing provisions of Part 75, which currently govern the Acid Rain Program ("ARP") and the NO_x Budget Program ("NBP"). Specifically, EPA would add a new Subpart I with five new sections (§§ 75.80 through 75.84). By adding the mercury mass emissions monitoring requirements to Part 75, EPA would be able to utilize many of the existing provisions in a well developed regulatory structure with which utilities are familiar, rather than attempting to create a new system. Although there are a few provisions in Part 75 that UARG does not believe can be applied to mercury monitoring systems at this time, UARG believes many other provisions in Part 75 can be applied and that there are significant advantages to using that approach. Among the advantages are (1) use of existing certified monitoring systems for diluent gas, volumetric

flow, and moisture, (2) use of existing procedures to account for partial operating hours and determine when tests are due, and (3) use of an existing recordkeeping and reporting structure.

In order to evaluate the monitoring and compliance provisions in EPA's cap-and-trade proposal, UARG asked its technical consultants at RMB to review the proposal. RMB's specific comments are set out in the attached RMB Technical Review Comments (Attachment 6).

UARG agrees with and adopts RMB's comments.

a. Method for Determining Mass Emissions

To support a trading program, all mercury emissions measurements under Part 75 would be recorded in terms of mass per hour. Mass emissions can be calculated two ways. The first method is to monitor the emission rate (in lbs/Btu), the unit heat input rate (in mmBtu/hr), and the unit operating time (hr). To do that, the source would need a mercury-diluent CEMS (consisting of a mercury concentration monitoring system and a diluent monitor -- O₂ or CO), a flow rate monitoring system, and a continuous moisture monitoring system (or appropriate default value). The second method is to monitor mercury concentration (micrograms/dscm), stack gas flow rate (scfh), and the unit operating time (hr). To do that, the source would need a mercury concentration monitoring system, a flow rate monitoring system, a continuous moisture monitoring system (or appropriate default value). EPA's proposal provides sources the option between those two methods.³⁴⁷ UARG supports EPA's decision to allow that choice. That is the same approach EPA has taken with respect to NO_x in the NO_x SIP Call (Part 96 and Part 75, Subpart H), and the Section 126 program (Part 97 and Part 75, Subpart H). UARG believes that the experience under those programs demonstrates that both methods of calculating mass emissions are acceptable for a trading program.

³⁴⁷ Proposed 40 C.F.R. § 75.81(a) and (b).

b. Choice of Monitoring Systems

Like the proposed MACT in Subpart UUUUU, EPA's proposed Part 75 revisions include provisions for use of both Hg CEMS and a sorbent trap monitoring system meeting Method 324. However, rather than allow all sources the option of choosing which method to use at a particular source, EPA proposes to restrict use of Method 324 either to (1) low-emitting units (*e.g.*, units having estimated 3-year average mercury emissions of 9 lbs or less for the three calendar years used to allocate mercury allowances (referred to as "*Alternative 1*"), or (2) units that perform relative accuracy testing of their Method 324 systems on a quarterly basis ("*Alternative 2*").³⁴⁸ Under *Alternative 1*, EPA requests comment on alternative thresholds of 29 lbs/yr, 46 lbs/yr, and 76 lbs/year, which based on the 1999 ICR data would represent 39, 50, and 65 percent, respectively, of the affected units. Under *Alternative 2*, EPA would require an annual 9-run RATA and a 3-run relative accuracy audit ("RAA") in each of the other quarters for which the unit operates at least 168 hours.³⁴⁹ EPA also proposes to prohibit new units that commence commercial operation more than 6 months after publication of the final rule from using Method 324.³⁵⁰ UARG does not believe that either of EPA's proposed alternatives to restrict use of Method 324 is appropriate or justified.

As described below, there is no legal, policy, or technical justification for restricting use of Method 324 to a particular class of units, or requiring relative accuracy audits more frequently than annually. To the contrary, all arguments weigh in favor of allowing sources a choice of monitoring systems, just as EPA proposes to do in the MACT.

³⁴⁸ *Id.* at § 75.81(b); Proposed Appendix A, § 2.7 and Figure 1.

³⁴⁹ 68 Fed. Reg. at 12417.

³⁵⁰ Proposed 40 C.F.R. § 75.81(c).

Alternative 1. The rationale EPA offers to support limiting use of Method 324 to low-emitting units (“*Alternative 1*”) is that it is “consistent with the way that EPA has implemented the Acid Rain and NO_x Budget Programs.”³⁵¹ According to EPA, because those programs have required CEMS “with few exceptions,” the mercury trading program should similarly favor CEMS and limit alternatives. EPA goes on to explain that alternatives to CEMS have been allowed under the ARP and NBP only where (1) the emissions were demonstrated to be very low relative to the cap, or (2) the alternative is demonstrated to be capable of generating data that has the same “precision, reliability, accuracy, and timeliness” as CEMS. EPA also suggests that the only approved alternatives under those programs -- *e.g.*, Appendices D and E of Part 75 for oil- and gas-fired units -- were justified based on low emissions relative to the cap.³⁵² EPA’s rationale is seriously flawed.

First, UARG does not understand why consistency with the ARP or NBP should be a criterion for evaluating alternatives to CEMS under a mercury trading program. Mercury is a very different substance, the available technologies for monitoring mercury are different, and the proposed mercury trading program is not governed by the same statutory criteria as the ARP.

At the time the ARP was enacted, CEMS technology for SO₂ and NO_x had been in use for more than 10 years and had already been proven reliable for coal-fired sources under Subpart Da of the NSPS. CEMS were also the only continuous method available for direct measurement of SO₂ and NO_x in stack gases, other than the continuous reference methods (*e.g.*, Methods 6C and 7E) which are basically CEMS. As a result, in CAA § 412, Congress directed EPA to require CEMS for SO₂ and NO_x for use in the ARP and to limit alternative monitoring systems to

³⁵¹ 69 Fed. Reg. at 12416.

³⁵² *Id.*

those that were “demonstrated as providing information with the same precision, reliability, accessibility, and timeliness as that provided by CEMS” (referred to as the “PRAT” criteria).³⁵³

Hg CEMS, on the other hand, are in the early stages of development and have not yet been used in any regulatory program. Hg CEMS also are not the only continuous method of measuring mercury in stack gases. Like continuous reference methods, which are allowed in lieu of CEMS without restriction under the ARP and NBP,³⁵⁴ Method 324 measures emissions in stack gases on a continuous basis.

Moreover, unlike SO₂ and NO_x, there is no statutory preference for Hg CEMS use in a trading program. Mercury is not subject to Congress’ directive in CAA § 412.³⁵⁵ Section 111, the provision upon which EPA proposes to rely, does not have any provisions directly related to monitoring methods or alternatives. Section 112, which does address monitoring methods for HAPS, does not even mention CEMS, but instead provides EPA authority to establish “by rule, test measures and other analytic procedures for monitoring and measuring emissions” of HAPS. EPA exercised that authority by proposing Method 324. In short, there is no “consistency” requirement. Accordingly, Method 324 should be evaluated on its own merits and not based on some preconceived preference for CEMS under the ARP or NBP.

EPA has already concluded based on “recent field studies” that sorbent trap monitoring systems “are capable of providing accurate measurements of mercury concentrations that

³⁵³ Sections 75.40 through 75.48 of the ARP requirements for alternative monitoring systems mirror those statutory criteria. EPA’s description of the criteria in Part 75 as “precision, reliability, *accuracy*, and timeliness” is an error. 69 Fed. Reg. at 12416 (emphasis supplied).

³⁵⁴ See, e.g., 40 C.F.R. § 75.30(b).

³⁵⁵ Although the NBP also is not subject to CAA § 412, there was no reason to question the preference for NO_x CEMS in that program, because NO_x CEMS technology is well developed and already required for many affected units under the ARP, NSPS, and SIPs.

compare favorably to measurements made with mercury CEMS.”³⁵⁶ EPA similarly concluded in its mercury MACT proposal that, aside from the inability to provide data in “real-time,” sorbent trap systems were equal to Hg CEMS in their ability to provide the data necessary to calculate compliance with the proposed MACT.³⁵⁷ Some of EPA’s data even indicate that sorbent traps might be more accurate than Hg CEMS.³⁵⁸ And, when compared to the approved alternatives under the ARP and NBP (*e.g.*, Appendix D fuel sampling), Method 324 could be viewed as more “consistent” with a preference for CEMS because, unlike those methods, it provides a direct measurement of stack emissions just like a Hg CEMS.³⁵⁹ Thus, the only possible question EPA could ask about Method 324 is the same question EPA contemplated with respect to Appendix D fuel sampling under the ARP -- that is whether the absence of “real-time” data would be a significant factor in an annual trading program. UARG does not believe real-time data are necessary for an annual trading program, and neither does EPA.

Contrary to EPA’s suggestion, when the Agency proposed the “Appendix D” fuel sampling and analysis alternative to determine SO₂ emissions for gas- and oil-fired units under the ARP, the Agency did *not* rely on the units’ low-emitting status relative to the SO₂ cap. EPA did so based on the merits of the method and its “good performance” with respect to the PRAT criteria in § 412.³⁶⁰ Although EPA initially proposed a 24-hour turnaround on Appendix D

³⁵⁶ 69 Fed. Reg. at 12417.

³⁵⁷ *Id.* at 4681.

³⁵⁸ See RMB Technical Comments, at 5-4 (Attachment 6).

³⁵⁹ *See id.*

³⁶⁰ Acid Rain Program: Permits, Allowance System, Continuous Emissions Monitoring, and Excess Emissions, 56 Fed. Reg. 63002, 63089 (1991); *see also* RMB Technical Comments (continued...)

analyses in order to respond to the “timeliness” requirement of CAA § 412 (to which mercury is not subject), EPA’s final ARP rule extended that to 30 days, based on a number of factors including the practicalities of laboratory analysis.³⁶¹ Accordingly, EPA has already considered whether the availability of emissions data on a “real-time” or even daily basis are important to an annual trading program and determined that it is not.

Although mercury is not subject to the CAA § 412 criteria, under EPA’s proposal it would be subject to the existing ARP/NBP trading rules. As such, Method 324 results (like Appendix D results) would have to be available within 30 days of the end of a calendar quarter for inclusion in a quarterly report. Although laboratory analysis of Method 324 results *today* are not relatively slow, turnaround times undoubtedly will increase significantly once there is a market for analysis -- an assumption that is no less valid than EPA’s assumption that there will be NIST traceable gas available to calibrate Hg CEMS by January 1, 2009. Moreover, any concerns EPA might have about turnaround time is no basis for limiting the *number* of units that should be allowed to consider use of Method 324, as EPA proposes. Any utility source ought to be allowed to use Method 324 as long as they can meet the reporting requirement.

UARG believes that EPA’s proposal to restrict use of Method 324 to units that emitted mercury below some threshold lbs/year during 1998-2002 (*i.e.*, the years used for allowance

at 5-4 (“the Appendix D procedure is more accurate than an SO₂ monitor when the fuel is gas or oil”) (Attachment 6).

³⁶¹ 56 Fed. Reg. 63321; Acid Rain Program: General Provisions and Permits, Allowance System, Continuous Emissions Monitoring, Excess Emissions and Administrative Appeals, 58 Fed. Reg. at 3642-43 (1993). Although EPA’s final rule for Appendix D included a provision requiring analysis in less than 30 days if requested during an audit, 58 Fed. Reg. 3742 (the current rule requires analysis no later than 5 business days, Part 75, Appendix D, § 2.2.8), UARG is not aware of any case under the ARP where EPA has actually sought a faster turn-around time on analysis for purposes related to the trading program.

allocations) amounts to nothing more than an *arbitrary* limit on the number of units that could use the Method. EPA has provided no data or technical argument to suggest that the sorbent trap technology should be limited to units emitting below a certain level.³⁶² Even if there were such data, however, the restriction would still be arbitrary. Under EPA's proposal, a source that installs controls after 2002 might come well under EPA's lbs/year threshold (and therefore be equally low-emitting), but nonetheless be prohibited from using the method based on its past operations. UARG can think of no rational argument for determining a source's ability to choose between two methods that appear to be equally accurate based on a low-emitting concept, or to base a unit's low-emitting status on a past (as opposed to present) level of control. While use of Method 324 might be generally more attractive to units with lower mercury emissions because of the expense of analysis of traps, there is no legal, policy, or technical basis for imposing a regulatory restriction on its use.

In sum, EPA's rationale for its proposal to limit use of sorbent trap monitoring systems meeting Method 324 to some subset of low-emitting units is unfounded. All units should have the choice between Hg CEMS and a sorbent trap method meeting Method 324.

Alternative 2. After acknowledging sorbent trap monitoring systems provide data that are as accurate as Hg CEMS, EPA advances a second proposal ("*Alternative 2*") that would allow use of sorbent trap for all units, but only if a quarterly RAA or RATA is performed.³⁶³ EPA's rationale for this restriction is that because other Part 75 monitors (*e.g.*, Hg, SO₂, and NO_x

³⁶² This absence of justification is in direct contrast to EPA's analysis with respect to approval of the alternative Appendix E procedure for determining NO_x emissions from gas-fired peaking units under the ARP, which was deliberately limited to a specific class of low-emitting units because of the admittedly lower level of accuracy in the emissions calculations it provided. 58 Fed. Reg. at 3644.

³⁶³ 69 Fed. Reg. at 12417.

CEMS) are subject to quarterly quality assurance requirements (*i.e.*, a quarterly linearity check with calibration gases), the sorbent trap system should also have a quarterly test.³⁶⁴ EPA proposes requiring the relative accuracy test, not based on the usefulness of the test results or some identified need for additional relative accuracy testing, but rather because EPA could think of no existing Part 75 test other than relative accuracy test that could be performed on a sorbent trap monitoring system.³⁶⁵ EPA's proposal is based on the same baseless and arbitrary concern for "consistency" with existing requirements for CEMS as *Alternative 1* and should be abandoned.

First, contrary to EPA's suggestion, there is nothing magic about a quarterly test and no reason to require all monitoring systems in trading programs to perform a quarterly test just because CEMS are required to do so. EPA has already recognized that point in approving Appendix D under the ARP and NBP without any quarterly quality assurance check requirement. Rather than arbitrarily require a quarterly check under Appendix D, EPA considered the type of technology used under the method and established checks appropriate for that technology, which in the case of Appendix D is calibration of the fuel flowmeter every four QA operating quarters.³⁶⁶

The purpose of the requirement under Part 75 for a quarterly "linearity check" of a CEMS (and the similar CGA -- cylinder gas audit -- in the NSPS, Part 60, Appendix F, PS 1, § 5.1.2) is to periodically check the calibration of the instrument over its full measurement range

³⁶⁴ *Id.*

³⁶⁵ *Id.*

³⁶⁶ 40 C.F.R. Part 75, Appendix D, § 2.1.6.

to ensure a linear response.³⁶⁷ Both the quarterly linearity check and the daily calibration error tests are procedures that are specific to the technology upon which CEMS are based, which requires periodic calibration of the instrument response to a known value to compensate for instrument drift. The sorbent trap system that is installed on a utility source does not utilize the same technology and therefore does not require calibration at the installation site.

Performance of a quarterly relative accuracy test, as EPA proposes, would be similarly useless. Although it is possible to run the comparison of the Method 324 results to another EPA method (*e.g.*, Method 29 or the Ontario-Hydro method) and calculate a result, the sorbent trap cannot be calibrated to another test method any more than it can be calibrated to a reference gas. As described above in UARG's comments on the proposed quality assurance requirements under the MACT, because Method 324 is itself a test method, UARG does not believe that the relative accuracy test is necessary for Method 324 at all.³⁶⁸ Although UARG decided, based on the fact that Method 324 is a relatively new test method, not to oppose an annual RATA, UARG does oppose more frequent relative accuracy testing.

Failure to require quarterly testing of Method 324 under Part 75 does *not* mean that the method is not subject to vigorous periodic quality assurance. Method 324 itself contains a number of stringent requirements designed to ensure the quality of data under the method, including pre- and post-sampling leak checks for each sorbent trap used, analysis of the backup section, paired-trains, field blanks, field spikes, solution blanks, duplicate analysis of samples, and calibration of the instrument used in the laboratory following every 10 samples.³⁶⁹ This

³⁶⁷ 56 Fed. Reg. at 63070.

³⁶⁸ See RMB Technical Comments, at 5-4, 5-5 (Attachment 6).

³⁶⁹ Proposed Method 324, § 9-11.

latter requirement for the laboratory instrument calibration serves the same purpose as, but is arguably more stringent than, the quarterly linearity check required for CEMS. EPA appears to have completely ignored these quality control procedures in evaluating use of Method 324 under Part 75.

As proposed, *Alternative 2's* sole accomplishment is creation of a disincentive for sources to use Method 324. If EPA believes that there are actual QA/QC issues with sorbent trap monitoring systems under Method 324, EPA should identify those issues and propose tests or procedures to address them. UARG already has suggested some additional procedures for labeling and tracking of traps. Having identified no such issues, EPA has no basis to condition use of Method 324 on additional relative accuracy testing. EPA should abandon the proposed quarterly testing requirement and allow an unrestricted choice of Hg CEMS meeting PS-12A or sorbent trap meeting Method 324.

New Units. Consistent with EPA's bias towards CEMS in *Alternatives 1 and 2*, EPA proposes to prohibit any new units that commence commercial operation more than 6 months after publication of the final rule from using any method other than Hg CEMS.³⁷⁰ EPA's rationale for this restriction is that it is "consistent with the monitoring requirements for other pollutants (*e.g.*, SO₂, NO_x) under NSPS and the Acid Rain Program."³⁷¹ UARG disagrees with EPA's proposal.

UARG does not understand the logic of EPA's comparison to the ARP, which does not distinguish between new and existing units for the purposes of evaluating monitoring alternatives. New coal-fired units under the ARP must install SO₂ and NO_x CEMS, not because

³⁷⁰ Proposed 40 C.F.R. § 75.81(c).

³⁷¹ 69 Fed. Reg. at 12416.

they are new units, but because the ARP does not include any alternative monitoring methods for coal-fired units. If EPA could justify requiring Hg CEMS simply by noting that the ARP requires coal-fired units to use CEMS for SO₂ and NO_x, EPA need not have bothered with *Alternative 1* at all.

EPA's proposal also continues to ignore the very obvious fact that SO₂ and NO_x CEMS are required, not because they are "CEMS" *per se*, but because the technology is well established and there is no other comparable method for continuous monitoring of stack gases for those pollutants. That is not the case for mercury, which also has Method 324. Unless EPA can present some technical reason why CEMS are more appropriate for new units than Method 324, EPA must abandon its proposed restriction.

2. Special Rules for Sorbent Trap Systems (Method 324)

To govern those units that use Method 324, EPA proposes to add § 75.15 with special provisions for use of sorbent trap systems. UARG has concerns about several of the proposed requirements. First, in subsection § 75.15(e), EPA sets out procedures for proportional sampling that require what appear to be manual adjustment of the sampling rate in relation to load. The proposed adjustments are not possible as a practical matter, and are in conflict with procedures in Method 324 that allow automated input of stack flow or load data into the sorbent trap system and automated adjustment of flow rate. As described above in comments on Method 324, UARG requests that EPA remove this subsection or revise it to be consistent with Method 324.³⁷²

Second, in subsection § 75.15(h), EPA proposes to require, for each pair of sorbent traps analyzed, that the higher of the two mercury concentrations be used for calculating and reporting

³⁷² See RMB Technical Comments, at 5-6 (Attachment 6).

mercury emissions. UARG objects to use of the higher of the concentrations in the two paired traps. If paired traps are required, EPA should utilize standard procedures for paired trains and allow for use of the average of the two values as long as they are within a specified RSD. UARG also recommends that EPA consider the procedure described in RMB's comments if the values are not within that standard.³⁷³

3. Quality Assurance/Quality Control

a. Bias Test

EPA proposes to subject Hg CEMS and sorbent trap monitoring systems to the same "bias test" and "bias adjustment factor" requirements as SO₂, NO_x, and volumetric flow monitors.³⁷⁴ UARG strenuously objects to this aspect of the proposal. UARG has never believed that this test was useful or appropriate.³⁷⁵ Although EPA rejected UARG's comments and adopted a bias test, EPA did so only after analyzing historical SO₂ and NO_x data from Subpart Da units as well as more recent field testing data and committing in the rule to conduct further studies.³⁷⁶ Field testing data were of the most significance for EPA's adoption of the bias test for volumetric flow monitors, for which there was little historical data, and EPA recognized the need to engage the issue and examine data as to whether "the bias test performance standard is within the technical capabilities of current [flow monitoring] technology."³⁷⁷ EPA has

³⁷³ *See id.*

³⁷⁴ Proposed 40 C.F.R. §§ 75.20(c), 75.24, Appendix A, § 3.4.3 and 7.6, Appendix B, § 2.3.

³⁷⁵ *See, e.g.,* Comments of the Utility Air Regulatory Group on EPA's Proposed Part 75 Regulations (Feb. 12, 1992) (Docket No. A-91-69-M-IV-D-185).

³⁷⁶ 58 Fed. Reg. at 3627; former § 75.7.

³⁷⁷ 58 Fed. Reg. at 3628.

provided no such analysis to support application of the bias test to Hg CEMS or sorbent trap systems. Nor has EPA explained the appropriateness of applying a bias test and adjustment factor to Method 324, when it has already satisfied the same standards for bias and precision as the Ontario-Hydro method under EPA Method 301.³⁷⁸ In short, EPA's proposal is without support and the requirement for a bias test for Hg CEMS and Method 324 should be abandoned.³⁷⁹

b. Appendix A and B Specifications

In general, EPA proposes to subject Hg CEMS to all of the same QA/QC requirements as SO₂ and NO_x CEMS, but with more lenient performance specifications. As such, EPA has included regular and low-emitter calibration and relative accuracy standards for Hg CEMS. UARG commends EPA for recognizing the need for low-emitter standards under Part 75 and encourages EPA to extend the same concept to PS 12A, which currently conflicts with Part 75. UARG is very concerned, however, by the lack of data demonstrating that any of the standards in Part 75 or PS 12A are achievable by Hg CEMS. Accordingly, UARG requests that EPA commit to collecting data and evaluating the standards as soon as calibration gases are available, so that the specifications can be adjusted if necessary.³⁸⁰

Consistent with the above comments on proposed PS 12A, UARG is particularly concerned with EPA's mandate in Part 75, § 75.20(c)(1)(vi), Appendix A § 2.2.3, and Appendix B, § 2.6, that Hg CEMS be designed to allow calibration using a HgCl₂ standard and that they

³⁷⁸ See Dec. 10, 2003 Memorandum to W. Grimley at § 2.2.1 (Docket No. OAR-2002-0056-0022).

³⁷⁹ See also RMB Technical Comments, at 5-7 (Attachment 6).

³⁸⁰ See *id.* at 5-7.

pass an initial and monthly 3-point check of the converter with that standard, when no standard is commercially available. Accordingly, UARG requests that EPA revise the rule to qualify that the test is only required if a HgCl₂ standard meeting some reasonable accuracy specification is “commercially available.”³⁸¹

With respect to the proposed calibration error standard in Appendix A, § 3.1 UARG notes that the standard should read “5% of the span value if the span value is 20 micrograms/dscm or greater, or 1 microgram/dscm if the span value is less than 20 micrograms/dscm.” As written, the specification penalizes any monitor with a span value between 10 and 20 micrograms/dscm.³⁸²

Another aspect of the regulations UARG believes warrants clarification is the relevance of particle-bound mercury to the Part 75 measurements. As PS 12A and Method 324 make clear, both methods are designed to measure vapor-phase mercury. Consistent with that, UARG requests that EPA make clear in the Part 75 RATA requirements (as EPA did in PS 12A, § 8.6.2) that the filterable portion of the reference method sample is not included when making the comparison to the CEMS. Consistent with that change, EPA should also remove the requirements in § 75.59(a)(7) to record and report RATA results related to particle bound mercury, or provide justification for collection and submission of that additional data.

Finally, with respect to Method 324 sorbent trap monitoring systems, UARG questions EPA’s requirement in Appendix B, § 1.5.4 that laboratories performing Method 324 be certified by the International Organization for Standardization (“ISO”) to have proficiency that meets the requirements of ISO 9000. EPA has not provided any information or justification for such a

³⁸¹ *See id.* at 5-8.

³⁸² *See id.*

requirement. Before requiring certification, EPA must consider the additional cost associated with the certification, the availability of certified laboratories, and the benefits that will be provided from whatever additional requirements the standard impose. EPA has not even gone so far as to describe what those additional requirements might be. Although UARG members want to obtain the best possible data from laboratories, there is nothing in the record to show that certification under ISO 9000 will result in better data. Because laboratory errors generally result in higher values, utilities may already have sufficient incentive to utilize labs with good practices to render formal certification unnecessary. Accordingly, UARG requests that EPA perform additional analysis of the impacts and benefits of the proposed requirement.³⁸³

4. Data Availability and Missing Data

EPA proposes to address missing data from Hg CEMS by simply adopting the missing data scheme applicable to SO₂ CEMS.³⁸⁴ UARG objects to this approach. As EPA knows, the missing data provisions for SO₂ were adopted after significant analysis of SO₂ emissions data to determine the impact of the scheme on reported emissions.³⁸⁵ The impact of a missing data scheme on reported emissions is directly related to the length of the missing data periods, the overall amount of missing data, and the variability of emissions in the look-back period. As explained elsewhere in these comments, neither EPA nor UARG knows how these monitoring systems will perform in practice or whether the monitoring systems will be able to meet the required performance specifications. As a result, EPA has no data by which to analyze the

³⁸³ *See id.*

³⁸⁴ Proposed Table 1 and 40 C.F.R. § 75.38.

³⁸⁵ *See* 58 Fed. Reg. at 3634-38; Comments of the Utility Air Regulatory Group on EPA's Proposed Part 75 Regulations (Feb. 12, 1992) (Docket No. A-91-69-M-IV-D-185).

impacts of its missing data proposal. Until EPA has data to support a specific missing data scheme, EPA should utilize an hour before/hour after approach similar to the initial missing data procedures.³⁸⁶

For Method 324 sorbent trap monitoring systems, EPA proposes a missing data scheme that requires substitution of increasingly high values whenever results from either of the two traps are not available (*e.g.*, 1.5 times the highest value in the last 12 months when availability is between 80 and 90 percent, and “maximum potential [mercury] concentration” when below 80 percent).³⁸⁷ Like Hg CEMS, neither EPA nor utilities have any idea what data availability will be for these systems, particularly using EPA’s proposed requirements for paired traps. Although availability is likely to be much better than Hg CEMS, a single missing data event will result in a greater amount of lost data because each trap provides several days worth of data. As with Hg CEMS, EPA has no basis for its current proposal. Until EPA has some reasonable amount of data to assess the impacts of its missing data scheme, EPA should abandon the proposed scheme in favor of a less punitive rule.³⁸⁸

As with SO₂ CEMS, EPA proposes to require sources that utilize a FGD system to maintain records of scrubber operating parameters for each mercury missing data period in order to show proper operation of the scrubber.³⁸⁹ Because recording of FGD parameters generally is not automated, this requirement could become very burdensome if there is a significant amount of missing data. As a result, UARG requests that EPA consider allowing sources the option of

³⁸⁶ See RMB Technical Comments, at 5-3, 5-4, 5-7 (Attachment 6)

³⁸⁷ Proposed 40 C.F.R. § 75.39(d)(1) - (4).

³⁸⁸ See RMB Technical Comments, at 5-4, 5-7 (Attachment 6).

³⁸⁹ Proposed 40 C.F.R. §§ 75.38(b) and 75.39(e).

utilizing parameters other than control device operating parameters, such as documented compliance with an SO₂ permit limit using the SO₂ CEMS, to establish proper operation of the FGD during mercury missing data periods.

EPA proposes to revise § 75.20(d) to include Hg CEMS in the list of non-redundant backup monitoring systems that can be used for up to 720 operating hours without a RATA. UARG requests that EPA revise this section, and other sections regarding use of backup monitoring systems and missing data, including § 75.80(f), to allow use of sorbent trap monitoring systems as a backup to Hg CEMS and *vice versa*. EPA should also allow use of additional paired traps as a backup to a sorbent trap monitoring system.

Finally, as with SO₂, NO_x, diluent, and flow, EPA proposes to use the concept of “maximum potential” values to fill in missing data for mercury when a mercury monitoring system is not certified, or missing data fall below a certain level. UARG does not believe that the concept of maximum potential values should be applied to mercury in the same manner as other pollutants. That is because sources that utilize controls are unlikely ever to emit at the maximum potential level as a result of requirements to operate those controls to meet emission standards for other pollutants. Although the concept of maximum potential is designed to be punitive in order to encourage good monitoring system availability, the absence of data on what availability is reasonably achievable make such a system unsupportable at this time.³⁹⁰

5. Miscellaneous Issues Under Proposed Subparts Da and GGGG

a. Applicability

EPA proposes to incorporate mercury and nickel standards into Subpart Da through § 60.45a(a) and (b) and § 60.46a, respectively. As revisions to the NSPS, applicability of those

³⁹⁰ See RMB Technical Comments at 5-7.

limits to new units is limited to units that commenced construction after the proposal date of January 30, 2004. EPA proposes to reflect that limited applicability only by means of parenthetical statements in the compliance provisions in § 60.48a(m) and (n). UARG does not believe that EPA's approach is sufficient to make applicability clear. Instead, EPA should follow the approach it took with promulgation of a new output-based NO_x standard and also include a clear statement of applicability in the provisions setting out the new standards.³⁹¹

In addition, although the proposed rule provisions make clear that the Subpart Da standards would apply only to units constructed after the proposal date, the preamble and the proposed guidelines at Subpart GGGG suggest that the Subpart Da standards also would apply to units that were "modified" or "reconstructed" after the proposal date of January 30, 2004.³⁹² Accordingly, UARG requests that EPA revise § 60.4010 and make clear in the final preamble that the stricter Subpart Da standards apply only to newly constructed units. As explained in comments above, the proposed Subpart Da standards (which are equivalent to the proposed MACT standards for new units) are already too stringent for new units to meet, and could not be met by reconstructed or modified units.

b. Definitions

Although EPA uses the terms "coal-fired electric utility steam generating unit," "integrated gasification combined cycle electric utility steam generating unit," and "oil-fired electric utility steam generating unit" to define applicability in the proposed rules, those terms are not defined anywhere in the proposed revisions (or the existing Part 60). EPA should add

³⁹¹ See, e.g., § 60.44a(d).

³⁹² 69 Fed. Reg. at 4690; 40 C.F.R. § 60.4010.

definitions for those units that are consistent with the definitions in proposed Subpart UUUUU and with UARG's comments on those definitions.

c. Quality Assurance/Quality Control and Missing Data

Like Proposed Subpart UUUUU, proposed Subpart Da § 60.50a(j) would require Hg CEMS and sorbent trap systems to perform some QA/QC requirements “in accordance with” Procedure 1 of Part 60, App. F. As noted above, this presents some issues for sorbent trap systems because Procedure 1 does not include all of the information necessary to perform those tests. In addition, with the use of Part 60 QA/QC requirements in Subpart Da, new units that are subject to both the NSPS and the cap-and-trade program would be subject to both the specified Part 60, Appendix F, and the Part 75, Appendix B, QA/QC requirements. EPA should avoid imposing these duplicative and inconsistent requirements by explicitly stating in the Subpart Da revision that Hg CEMS and sorbent trap systems meeting the requirements of Part 75 do not have to comply with Part 60, Appendix F, procedures set out in § 60.50a(j). EPA should use the Subpart Da NO_x revision in § 60.47(c)(2) as a model.

d. Compliance Calculations

Section § 60.50a(h)(1), which covers calculation of mass mercury emissions from Hg CEMS and Method 324, calls for calculating the “arithmetic average of all *weekly* emission rates for [mercury] for the 12 successive calendar months.” Subsequent subsections refer to calculation of mercury mass emissions “over a month” from CEMS³⁹³ and over the “emission rate period” from Method 324.³⁹⁴ It is not clear why § 60.50a(h)(1) refers to calculation of

³⁹³ 40 C.F.R. § 60.50a(h)(2).

³⁹⁴ 40 C.F.R. § 60.50a(h)(3).

weekly rates or how those rates fit into the more specific calculations. EPA needs to correct this discrepancy.

e. Other

Comments on other provisions in proposed Subparts Da and GGGG, that are identical to those in Subpart UUUUU, are set out above in section IV.

VII. Miscellaneous Issues

A. General

1. Revision of 40 C.F.R. § 63.2 to Include § 112(n)

In the preamble to the proposed rule, EPA notes its plan to revise the definition of “emission standard” in 40 C.F.R. § 63.2 to include a reference to § 112(n). UARG supports this revision. As explained in detail in Section I.A above, UARG believes that § 112(n)(1)(A) provides EPA independent legal authority to regulate hazardous air pollutant emissions for electric utility steam generating units. The proposed revision would simply confirm that authority.

2. Exemption for Small Units

UARG supports EPA’s proposed exemption for small units that emit less than 25 pounds of mercury per year.

Units that emit such small amounts of mercury present little, or no, risk to public health. For example, if the 25 pound limit is implemented, it would exempt approximately 390 of the over 1,100 coal fired units nationwide. Those units are responsible for only about 2 tons of the 45 tons of mercury emitted each year, or roughly 5%.³⁹⁵ The cost of controlling such small

³⁹⁵ EPA’s emissions estimate for these units is consistent with UARG’s. *See* 69 Fed. Reg. at 4699 (stating that the 396 smallest emitting coal-fired utility units account for less than 5 percent of total mercury emissions).

amounts of mercury would place a huge burden on the smallest units, many of which are owned by public power producers. The smallest units will be facing significant expenditures to comply with both the proposed CAIR requirements and mercury MACT concurrently. For many municipal and public power facilities, these added costs will force units to close, further weakening the national electricity grid.

3. The Record Does Not Permit an Evaluation of Some of EPA's Key Findings

UARG attempted to evaluate EPA's estimate that there would be 282,000 tons of additional solid waste as a result of the rule, together with the Agency's estimate that the energy impacts would be 1,418 million KWh.³⁹⁶ EPA's estimates can impact several other important conclusions that the Agency draws with respect to the impacts of the proposed rule, including its total costs and the ability of utilities to comply within the timeframe suggested by the Agency if additional solid waste or hazardous waste landfills must be permitted. Despite diligent attempts to review the rulemaking record, as described below, it was impossible to verify whether these estimates are reasonable.

The proposed rule referred to a memorandum by Jeffrey Cole of RTI International entitled "Methodology for Estimating Cost and Emissions Impact for Coal- and Oil-Fired Electric Utility Steam Generating Units National Emission Standards for Hazardous Air Pollutants" (December 2003) as supporting the Agency's estimates regarding the proposed rule's impact on water and solid waste.³⁹⁷ This report did not provide the key inputs to EPA's methodology and thus provided insufficient information to permit comment on EPA's estimates

³⁹⁶ 69 Fed. Reg. at 4706.

³⁹⁷ *Id.*

that an additional 282,000 tons of solid waste would be generated. We could find no reference in the preamble to any document that would support EPA's analysis regarding energy impacts. We did find in the rulemaking docket a memorandum by EPA's Clean Air Markets Division entitled "Economic and Energy Impact Analysis for the Proposed Utility MACT Rulemaking" (January 28, 2004). Once again, this document provided insufficient information to understand the basis for EPA's estimate of the energy impacts of the proposed rule.

In addition, EPA's proposed rule states as follows:

The benefits and cost analyses prepared for the proposed rule are detailed in the "Benefit Analysis of the CAA Section 111 Proposal to Reduce Mercury Emissions From Fossil-Fuel Fired Utilities" and the "Economic and Energy Impact Analysis of the Section 112 Utility MACT," respectively.³⁹⁸

The proposed rule provided no document number for either of these documents, and the docket index for OAR-2002-0056 contained no document with these titles. We eventually determined that a document entitled "Economic and Energy Impact Analysis for the Proposed Utility MACT Rulemaking" must be the document referred to in the *Federal Register* as "Economic and Energy Impact Analysis of the Section 112 Utility MACT." We also determined that a document listed in the docket index as "Proposed Utility MACT - Final Benefits Analysis Report" (the cover page of this document is actually entitled "Benefit Analysis for the Section 112 Utility Rule") must be the report referred to in the *Federal Register* notice as "Benefit Analysis of the CAA Section 111 Proposal to Reduce Mercury Emissions from Fossil-Fuel Fired Utilities."

Unfortunately, these documents did not provide sufficient information to understand the methods

³⁹⁸ *Id.* at 4714.

and assumptions that EPA used to estimate the amount of solid waste or the energy impacts of the proposed rule.

UARG would like to evaluate EPA's estimates of additional solid waste and the energy impacts of the proposed rule. We request that EPA provide the information needed to perform this evaluation as soon as possible so that we can undertake such an analysis. EPA should then reopen the comment period for a reasonable time to allow public comment on this issue.

4. EPA's Estimates of Compliance Costs are Too Low

EPA has projected annual compliance costs of \$1.6 billion in 2010, decreasing to \$1.1 billion in 2020 for its proposed MACT standard.³⁹⁹ EPA's cost estimates are too low in large part because of the simplifying assumptions that it made to accommodate the limitations of the ICF model that the Agency used to project costs.⁴⁰⁰ Specifically, EPA assumed for the purpose of its cost projections that all units would comply by using activated carbon injection combined with a fabric filter, followed by switching to lower mercury coals. EPA's presumed technology configuration may have been driven by its unrealistic assumption that a 90% mercury removal rate is possible with activated carbon injection and fabric filters.

In reality, many units will comply by using activated carbon injection followed by ESPs. This configuration has much greater annual operating and maintenance costs driven largely by a higher consumption rate of activated carbon.⁴⁰¹ UARG suggests that EPA use a more accurate method of projecting MACT cost by characterizing each individual unit in the database using

³⁹⁹ EPA, Clean Air Markets Division, Economic and Energy Impact Analysis for the Proposed Utility MACT Rulemaking (Jan. 2004) (Docket No. OAR-2002-0056-0048).

⁴⁰⁰ Cichanowicz Technical Comments, Section 4 (Attachment 8).

⁴⁰¹ *Id.*, Table 1.

site-specific conditions to determine whether activated carbon injection with a fabric filter or an ESP is the least cost option.⁴⁰² Without such an analysis, EPA's estimates are both very uncertain and surely much too low.

B. EPA's Requests for Comments

1. Cogeneration Issues

EPA requested comment on the frequency of units switching between being covered by the industrial boiler rule and the utility rule. Moreover, EPA requested comment on how to reconcile the differing stringencies of the two rules when this might occur.

UARG has contacted several of its member companies to determine the extent to which cogeneration units might switch between being covered by the industrial boiler rule and being covered by the utility rule. Many UARG members do not own or operate cogeneration units and most of those that do never generate electricity for sale to the grid. We learned that there are situations where a utility's cogeneration units supply steam and electricity to industrial users. Occasionally the industrial user may not operate for weeks or months while undergoing repairs, maintenance or refurbishments. During such periods, which tend to be of limited duration, the cogeneration units may generate electricity to the grid rather than sit idle.

Sections 112(a)(8) and 402(17) of the Clean Air Act have similar definitions of "utility unit" and allow cogeneration units above 25 MWe to supply up to 25 MWe electrical output or up to one-third of their potential electric output capacity to a utility power distribution system.⁴⁰³

⁴⁰² *Id.*, Table 1.

⁴⁰³ UARG believes EPA should implement "25 MW" and "one-third" tests on an annual basis, averaged over the appropriate three-year period, which is the approach reflected in EPA's Acid Rain Rules. *See* 40 C.F.R. § 72.6(b)(4).

The preamble to this proposed rule acknowledges this definition.⁴⁰⁴ We recommend that the final rule clearly allow cogeneration units above 25 MWe to supply up to 25 MWe electrical output or up to one-third of their potential electrical output capacity to a utility power distribution system for sale on an annual basis. This would likely minimize the possibility of non-utility units being inadvertently reclassified to utility units based upon unique situations of relatively short duration. In the event that a unit were reclassified and had to meet a more stringent standard, the Agency should provide a reasonable period of time for the unit to come into compliance.

2. System Wide Averaging

Compliance with traditional MACT standards is based on unit-by-unit compliance, or at best, facility-wide compliance. As applied to utility sources, this process is inefficient, and will result in higher compliance costs. As demonstrated by the Acid Rain program, and other programs, alternative forms of regulation can result in equal or better emission reductions while realizing substantial cost savings.

Section 112(n)(1)(A) does not require EPA to control each electric utility steam generating unit that emits mercury. As discussed numerous times throughout these comments, the provision instructs EPA to regulate as is “appropriate and necessary.”⁴⁰⁵ To the extent mercury emissions from power plants pose any conceivable public health hazard, they do so as a result of their contribution to the mercury “global pool.” Unit-specific, or even facility-specific, reductions of mercury emissions are unnecessary to reduce any conceivable mercury risks.

⁴⁰⁴ See 69 Fed. Reg. at 4657, col. 1.

⁴⁰⁵ See CAA § 112(n)(1)(A), 42 U.S.C. § 7412(n)(1)(A).

A Multi-Source Averaging Plan (“MSAP”) could be based on the existing CAA Title IV NO_x program which allows any group of units with the same owner/operator and Acid Rain Program Designated Representative to submit and implement a system-wide averaging plan. While this approach for mercury averaging would benefit larger utility systems, it is of far less benefit to small systems. Instead, it could be altered to allow averaging among different owners and operators. The CAA Title V permit program could serve to ensure multi-source compliance after a MSAP is approved by EPA. Additionally, the MSAP approach could be extended across state lines as appropriate, as is done in the CAA Title IV NO_x program.

Regardless of the precise approach adopted, if EPA decides it must impose a MACT limit, it should consider doing something on a wider scale. System-wide and regional approaches to mercury limits are consistent with § 112(n)(1)(A). Allowing averaging over a wider base would allow for a more flexible and effective approach than a traditional command and control unit-by-unit MACT.

3. Uniform Good Combustion Practices for Controlling Mercury and Nickel

EPA requested information on whether there are any good combustion practices that could control mercury or nickel. We have been unable to locate any combustion practices whatsoever that might control nickel. The single technology that has been investigated to control mercury has been demonstrated only on a pilot scale without full-scale applications.⁴⁰⁶

A mercury control combustion practice has been investigated by GE-EER on a pilot scale combustor that is several orders of magnitude smaller than a utility boiler. Essentially the technique achieves high loss on ignition (“LOI”) by combusting the fuel initially at low oxygen

⁴⁰⁶ Memorandum to Craig Harrison from Lowell L. Smith, Potential Combustion Modifications to Capture Mercury Emissions (Apr. 26, 2004) (Attachment 12).

concentrations to promote the formation of carbon in the boiler and the flyash. GE-EER primarily evaluated the mercury removal potential for low rank coals such as PRB and lignite. The vendor claims removal rates of up to 40 percent for low rank coals, although its own data seem to indicate that only 25 percent removals were actually achieved.⁴⁰⁷

This technology goes against the trend in the utility industry whereby burner manufacturers for years have been trying to minimize LOI to address the concern of the utility industry that high carbon levels make it impossible to sell flyash as an additive to cement. While the GE-EER “in-situ” carbon formation concept for mercury removal results looks interesting, it is far from being a commercial process. At this stage of development it is impossible to evaluate its true costs. For example, costs cannot be evaluated without knowing the extent to which this technology would result in lost income from the inability to sell flyash with high LOI levels and increased disposal costs of up to \$30-\$40 per ton for flyash. Finally, this technology might cause the radiant and convective boiler section tubes to be blanketed with carbon, decreasing boiler efficiency and increasing the cost of electric production.⁴⁰⁸

⁴⁰⁷ *Id.*

⁴⁰⁸ *Id.*