ORAL ARGUMENT SCHEDULED FOR APRIL 16, 2015

No. 14-1146

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, et al.

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent,

CITY OF NEW YORK, et al.

Intervenors.

Petition for Review of Settlement Agreement of the
United States Environmental Protection Agency

DEFERRED JOINT APPENDIX

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SETTLEMENT AGREEMENT

This Settlement Agreement is made by and between the following groups of Petitioners: (1) the States of New York, California, Connecticut, Delaware, Maine, New Mexico, Oregon, Rhode Island, Vermont, and Washington, the Commonwealth of Massachusetts, the District of Columbia, and the City of New York (collectively "State Petitioners"); and (2) Natural Resources Defense Council (NRDC), Sierra Club, and Environmental Defense Fund (EDF) (collectively "Environmental Petitioners"), and Respondent, the U.S. Environmental Protection Agency ("EPA") (collectively "the Parties").

WHEREAS, EPA published a final action entitled "Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units," 71 Fed. Reg. 9,866 (Feb. 27, 2006) (the "Final Rule");

WHEREAS, the Final Rule included amendments to the standards of performance for electric utility steam generating units subject to 40 C.F.R. part 60, subpart Da ("EGUs");

WHEREAS, in connection with this Final Rule, EPA declined to establish standards of performance for greenhouse gas ("GHG") emissions;

WHEREAS, State and Environmental Petitioners filed petitions for judicial review of the Final Rule under the Clean Air Act ("CAA") Section 111, 42 U.S.C. § 7411, contending, *inter alia*, that the Final Rule was required to include standards of performance for GHG emissions from EGUs;

WHEREAS, the portions of State and Environmental Petitioners' petitions for review of the Final Rule that related to GHG emissions were severed from other petitions for review of the Final Rule, and were formerly pending before the United States Court of Appeals for the District

of Columbia Circuit (the "Court") under the caption *State of New York, et al. v. EPA*, No. 06-1322;

WHEREAS, following the Supreme Court's decision in *Massachusetts v. EPA,* 549 U.S. 497 (2007), EPA requested remand of the Final Rule to EPA for further consideration of the issues related to GHG emissions in light of that decision;

WHEREAS, the Court remanded the Final Rule to EPA for further proceedings on GHG emissions in light of *Massachusetts v. EPA*, by its Order of September 24, 2007 (the "Remand Order");

WHEREAS, as of the date of this Settlement Agreement, EPA has not taken any publicly noticed action to respond to the Remand Order;

WHEREAS, the State Petitioners submitted letters to EPA dated June 16, 2008 and August 4, 2009 inquiring as to the status of EPA's action on the remand and stating their position that EPA had a legal obligation to act promptly to comply with the requirements of Section 111, and Environmental Petitioners submitted a letter to EPA on August 20, 2010 seeking commitments to rulemaking on GHG emissions from EGUs as a means of avoiding further litigation;

WHEREAS, EGUs are, collectively, the largest source category of GHG emissions in the United States, according to a recent EPA analysis. *See* 74 Fed. Reg. 56,260, 56,363 (Oct. 30, 2009);

WHEREAS, EPA's initial evaluation of available GHG control strategies indicates that there are cost-effective control strategies for reducing GHGs from EGUs;

WHEREAS, EPA believes it would be appropriate for it to concurrently propose performance standards for GHG emissions from new and modified EGUs under CAA section

111(b), 42 U.S.C. § 7411(b), and emissions guidelines for GHG emissions from existing affected EGUs pursuant to CAA section 111(d), 42 U.S.C. § 7411(d), and 40 C.F.R. § 60.22;

WHEREAS, the Parties wish to enter into this Settlement Agreement to resolve the State and Environmental Petitioners' request for performance standards and emission guidelines for GHG emissions under CAA sections 111(b) and 111(d) and to avoid further litigation on this issue, without any admission or adjudications of fact or law;

NOW THEREFORE, the Parties, intending to be bound by this Settlement Agreement, hereby stipulate and agree as follows:

1. EPA will sign by July 26, 2011, and will transmit to the Office of the Federal Register within five business days, a proposed rule under section 111(b) that includes standards of performance for GHGs for new and modified EGUs that are subject to 40 C.F.R. part 60, subpart Da. EPA shall provide the State and Environmental Petitioners a copy of the proposed rule within five business days of signature.

2. EPA will also sign by July 26, 2011, and will transmit to the Office of the Federal Register within five business days, a proposed rule under section 111(d) that includes emissions guidelines for GHGs from existing EGUs that would have been subject to 40 C.F.R. part 60, subpart Da if they were new sources. EPA shall provide the State and Environmental Petitioners a copy of the proposed rule within five business days of signature.

3. After considering any public comments received concerning the proposed rule described in Paragraph 1, EPA will sign no later than May 26, 2012, and will transmit to the Office of the Federal Register within five business days, a final rule that takes final action with respect to the proposed rule described in Paragraph 1. EPA shall provide the

Environmental and State Petitioners with a copy of its final action within five business days of signature.

4. If EPA finalizes standards of performance for GHGs pursuant to Paragraph 3, then based on consideration of the public comments received concerning the proposed rule described in Paragraph 2, EPA will sign no later than May 26, 2012, and will transmit to the Office of the Federal Register within five business days, a final rule that takes final action with respect to the proposed rule describe in Paragraph 2. EPA shall provide the State and Environmental Petitioners with a copy of its final action within five business days of signature.

5. EPA agrees that it will make staff available by telephone at least every 60 days to update State and Environmental Petitioners on EPA's progress in completing the actions described in Paragraphs (1) through (4). In addition, EPA will provide State and Environmental Petitioners with a status letter every 60 days, which shall include an affirmative statement of whether EPA believes it will timely complete all actions described in Paragraphs 1 through 4.

6. Upon EPA's fulfillment of each of the obligations stated in Paragraphs 1 through 4 above, this Settlement Agreement shall constitute a full and final release of any claims that State and Environmental Petitioners may have under any provision of law to compel EPA to respond to the Court's Remand Order with respect to GHG emissions from EGUs.

7. State and Environmental Petitioners shall not file any motion or petition seeking to compel EPA action in response to the Remand Order with respect to GHG emissions from EGUs unless EPA has first failed to meet an obligation stated in Paragraphs 1

through 4 above. If EPA fails to meet such an obligation, or if an EPA status letter described in Paragraph 5 does not affirm that EPA believes it will timely complete all actions described in Paragraphs 1 through 4, or if EPA fails to send a status letter as described in Paragraph 5 and does not promptly cure that failure upon receiving notice, State and Environmental Petitioners' sole remedy shall be to file an appropriate motion or petition with the Court or other civil action seeking to compel EPA to take action responding to the Remand Order. In that event, all Parties reserve any claims or defenses they may have in such an action, and the dates stated in Paragraphs 1 through 4 shall be construed to represent only the parties' attempt to compromise claims in litigation, and not to represent agreement that any particular schedule for further agency action is reasonable or otherwise required by law. State and Environmental Petitioners reserve all rights under the law to file petitions for review of final agency actions under this Settlement Agreement, pursuant to section 307(b), 42 U.S.C. § 7607(b).

8. This Settlement Agreement constitutes the sole and entire understanding of EPA and the Environmental and State Petitioners and no statement, promise or inducement made by any Party to this Settlement Agreement, or any agent of such Parties, that is not set forth in this Settlement Agreement shall be valid or binding.

9. Except as expressly provided in this Settlement Agreement, none of the Parties waives or relinquishes any legal rights, claims or defenses it may have. State and Environmental Petitioners reserve the right to seek attorneys' fees and costs relating to this litigation, and EPA reserves any defenses it may have relating to such claims.

10. The provisions of this Settlement Agreement can be modified at any time by written mutual consent of the Parties.

11. Except as expressly provided herein, nothing in the terms of this Settlement Agreement shall be construed to limit or modify the discretion accorded EPA by the CAA or by general principles of administrative law.

12. The commitments by EPA in this Settlement Agreement are subject to the availability of appropriated funds. No provision of this Settlement Agreement shall be interpreted as or constitute a commitment or requirement that EPA obligate, expend or pay funds in contravention of the Anti-Deficiency Act, 31 U.S.C. 1341, or any other applicable appropriations law or regulation, or otherwise take any action in contravention of those laws or regulations.

13. Nothing in the terms of this Settlement Agreement shall be construed to limit EPA's authority to alter, amend or revise any final rule EPA may issue pursuant to Paragraphs 3 or 4, or to promulgate superseding regulations.

14. The Parties agree and acknowledge that before this Settlement Agreement is final, EPA must provide notice in the Federal Register and an opportunity for public comment pursuant to CAA Section 113(g), 42 U.S.C. 7413(g). After this Settlement Agreement has undergone an opportunity for notice and comment, the Administrator and/or the Attorney General, as appropriate, shall promptly consider any such written comments in determining whether to withdraw or withhold her/his consent to the Settlement Agreement, in accordance with section 113(g) of the CAA. Within 30 days of the close of the public comment period, EPA shall provide written notice to State and Environmental Petitioners of any decision to withdraw or withhold consent or shall provide written notice of finality. This Settlement Agreement shall become final on the

date that EPA provides written notice of such finality to the State and Environmental Petitioners.

15. The undersigned representatives of each Party certify that they are fully authorized by the Party that they represent to bind that respective Party to the terms of this Settlement Agreement. This Settlement Agreement will be deemed to be executed when it has been signed by the representatives of the Parties set forth below, subject to final approvals pursuant to Paragraph 14.

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

FEB 28 2011

OFFICE OF
GENERAL COUNSEL

MEMORANDUM

SUBJECT: Approval of Settlement Agreement Resolving Potential Litigation concerning NSPS Rule regulating Greenhouse Gas Emissions from Electric Generating Units (EGU GHG NSPS Rule)

FROM: Scott Jordan, Attorney SJJ
Air and Radiation Law Office

THRU: Richard B. Ossias, RO
Associate General Counsel
Air and Radiation Law Office

TO: Scott C. Fulton
General Counsel

Background

On December 30, 2010, EPA published notice of a proposed settlement agreement to resolve threatened litigation over EPA's failure to respond to a remand in State of New York v EPA, No. 06-1322 (D.C.Cir.) which EPA took in 2007 to reexamine the issue of whether the New Source Performance Standard (NSPS) under Clean Air Act (CAA) section 111 for electric utility steam generating units (EGUs) should include standards of performance for greenhouse gases (GHGs). Under the terms of the proposed settlement agreement, EPA is required to sign a proposed rule by July 26, 2011 that includes (A) standards of performance under CAA section 111(b) for GHGs for new and modified EGUs that are subject to 40 CFR part 60, subpart Da, and (B) emissions guidelines under CAA section 111(d) for GHGs from existing EGUs that would have been subject to 40 CFR part 60, subpart Da if they were new sources. EPA is required to sign a final rule by May 26, 2012 that includes final determinations with regard to each of the elements in the proposed rule.

As required by CAA section 113(g), EPA published a notice in the Federal Register to afford persons not named as parties or intervenors in the case an opportunity to comment on the proposed settlement agreement (75 Fed. Reg. 82392 (December 30, 2010)). The Agency

received a total of 28 comments from various regulated entities and industry groups, state environmental agencies, environmental groups and individuals, and the Small Business administration Office of Advocacy (SBA).

Eight of the comments supported the settlement and urged EPA to act promptly to regulate GHGs from EGUs. The remaining comments opposed the settlement. Generally, the adverse comments asserted that the proposed deadlines do not provide sufficient time for EPA to conduct a thorough and reasoned rulemaking and to comply with various requirements for conducting the rulemaking. Under CAA section 113(g), if the comments disclose facts or considerations that indicate that consent to the settlement agreement would be inappropriate, improper, inadequate, or inconsistent with the Act, EPA or the Department of Justice may withdraw or withhold consent to the settlement agreement. We do not believe that the comments received disclose facts or considerations which indicate that consent is inappropriate, improper, inadequate, or inconsistent with the Act. We therefore recommend that you concur with finalizing this settlement.

RECOMMENDATION

We recommend that you concur in the Settlement Agreement in this case.

APPROVED: Scott C. Fulton

Scott C. Fulton, General Counsel

DISAPPROVED: _____

Scott C. Fulton, General Counsel

DATE: 3/2/11

MODIFICATION TO SETTLEMENT AGREEMENT

WHEREAS, on December 21, 2010, the following parties executed a "Settlement Agreement:" (1) the States of New York, California, Connecticut, Delaware, Maine, New Mexico, Oregon, Rhode Island, Vermont, and Washington, the Commonwealth of Massachusetts, the District of Columbia, and the City of New York (collectively "State Petitioners"); and (2) Natural Resources Defense Council (NRDC), Sierra Club, and Environmental Defense Fund (EDF) (collectively "Environmental Petitioners"), and Respondent, the U.S. Environmental Protection Agency ("EPA") (collectively "the Parties");

WHEREAS, the Settlement Agreement became final on March 2, 2011;

WHEREAS, on September 24, 2007, in a case entitled *State of New York, et al. v. EPA,* No. 06-1322, the United States Court of Appeals for the District of Columbia Circuit remanded to EPA a final action entitled "Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units," 71 Fed. Reg. 9,866 (Feb. 27, 2006) (the "Final Rule");

WHEREAS, Petitioners subsequently notified EPA of their potential claims to compel EPA to take action pursuant to the remand of the Final Rule;

WHEREAS, the Settlement Agreement resolves those potential claims;

WHEREAS, Paragraph 1 of the Settlement Agreement provided that: "EPA will sign by July 26, 2011, and will transmit to the Office of the Federal Register within five business days, a proposed rule under section 111(b) that includes standards of performance for GHGs for new and modified EGUs that are subject to 40 C.F.R. part 60, subpart Da. EPA shall provide the State and Environmental Petitioners a copy of the proposed rule within five business days of signature;"

WHEREAS, Paragraph 2 of the Settlement Agreement provided that: "EPA will also sign by July 26, 2011, and will transmit to the Office of the Federal Register within five business days, a proposed rule under section 111(d) that includes emissions guidelines for GHGs from existing EGUs that would have been subject to 40 C.F.R. part 60, subpart Da if they were new sources. EPA shall provide the State and Environmental Petitioners a copy of the proposed rule within five business days of signature;"

WHEREAS, Paragraph 10 of the Settlement Agreement provided that: "The provisions of this Settlement Agreement can be modified at any time by written mutual consent of the Parties;"

WHEREAS, EPA has engaged in an extensive public process in preparation of proposed rules that would satisfy its obligation under Paragraphs 1 and 2 of the Settlement Agreement, including five public "listening sessions" as well as additional meetings and discussions with a wide variety of public stakeholders;

WHEREAS, in the course of that public process, EPA has received a significant amount of useful information and ideas from a range of public stakeholders concerning issues relevant to the proposed rule;

WHEREAS, EPA requires additional time to consider the information and ideas presented by the public stakeholders to EPA;

WHEREAS, the Parties desire to enable EPA to give due attention and consideration to all information and ideas presented to EPA in the public process leading to the proposed rules, without any change to the date for taking final action as specified in Paragraphs 3 and 4 of the Settlement Agreement;

WHEREAS, the Parties now desire to modify Paragraphs 1 and 2 of the Settlement Agreement;

NOW THEREFORE, without any change to any other part of the Settlement Agreement, the parties hereby agree as follows:

1. Paragraph 1 of the Settlement Agreement shall be stricken, and replaced with the following: "EPA will sign by September 30, 2011, and will transmit to the Office of the Federal Register within five business days, a proposed rule under section 111(b) that includes standards of performance for GHGs for new and modified EGUs that are subject to 40 C.F.R. part 60, subpart Da. EPA shall provide the State and Environmental Petitioners a copy of the proposed rule within five business days of signature."
2. Paragraph 2 of the Settlement Agreement shall be stricken, and replaced with the following: "EPA will also sign by September 30, 2011, and will transmit to the Office of the Federal Register within five business days, a proposed rule under section 111(d) that includes emissions guidelines for GHGs from existing EGUs that would have been subject to 40 C.F.R. part 60, subpart Da if they were new sources. EPA shall provide the State and Environmental Petitioners a copy of the proposed rule within five business days of signature."

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91ST CONGRESS } SENATE { REPORT
2d Session } { No. 91-1196

NATIONAL AIR QUALITY STANDARDS ACT OF 1970

SEPTEMBER 17, 1970.—Ordered to be printed

Mr. BYRD of West Virginia (for Mr. MUSKIE, from the Committee on Public Works, submitted the following

REPORT

together with

INDIVIDUAL VIEWS

[To accompany S. 4358]

The Committee on Public Works, to which the bill (S. 4358), to amend the Clean Air Act as amended, was referred having considered the same, reports favorably thereon without amendment. An original bill (S. 4358) is reported in lieu of S. 3229, S. 3466, and S. 3546 which were considered by the Committee.

GENERAL STATEMENT

The committee bill would restructure the methods available to attack a critical and growing national problem of air pollution.

The legislation reported by the committee is the result of deep concern for protection of the health of the American people. Air pollution is not only an aesthetic nuisance. The Committee's concern with direct adverse effects upon public health has increased since the publication of air quality criteria documents for five major pollutants (oxides of sulfur, particulates, carbon monoxide, hydrocarbons and oxidants). These documents indicate that the air pollution problem is more severe, more pervasive, and growing at a more rapid rate than was generally believed.

The new information that carbon monoxide concentrations at levels damaging to public health occur in Chicago more than 22 percent of the time, and that other cities have similar problems with carbon monoxide and other pollutants, intensified the committee's concern to authorize a massive attack on air pollution. This bill is designed to provide the basis for such an attack.

ance with air quality standards in a particular air quality control region, the bill would require that new requirements be imposed by a State or locality on any sources in that region, including those sources already built and operated in compliance with the Federal standards of performance. In such instances, however, it is expected that States would allow a reasonable time for improvements to be made.

Finally, it should be noted that the bill would require the Secretary to delegate the certification function to any State which adopts a certification procedure which the Secretary finds meets the requirements set forth in this Section. It is expected that every effort will be made to have States assume this responsibility.

Some States, however, may have to adopt new legislation to meet the requirements of section 113(d)(1). The Committee sees no reason why the Secretary should not permit a State to perform as much of the work involved in certification as it can under its existing State law until such time as the State has adopted the necessary enabling legislation. It should be clear that when certification authority is delegated, the Secretary would retain unrestricted enforcement authority. However, it is expected that the Secretary would take enforcement action only where a State does not meet its obligations.

SECTION 114. EMISSION STANDARDS FOR SELECTED AGENTS

Knowledge and experience gained under the Air Quality Act of 1967, particularly through the development of criteria documents, has revealed that pollution agents and combinations of such agents fall into three general categories. The first of these categories are those pollution agents which are emitted from diverse stationary and moving sources into the ambient air and which are generally detectable through monitoring devices and systems. These pollution agents are those for which the criteria documents are to be issued and for which national ambient air quality standards and implementation plans are to be established.

The second category of air pollution agents includes those which are hazardous to the health of persons as defined in section 115.

The third category of pollution agents includes those agents which are not emitted in such quantities or are not of such a character as to be widely present or readily detectable on a continuous basis with available technology in the ambient air. The presence of these agents is generally confined, at least for detection purposes, to the area of the emission source. The information available at this time indicates that the following list of substances are most likely to be considered as the agents to be covered under this section:

> Arsenic, chlorine gas, hydrogen chloride, copper, manganese, nickel, vanadium, zinc, barium, boron, chromium, selenium, pesticides, radioactive substances.

The bill would limit the imposition of emission standards for these selected air pollution agents to those categories of stationary sources which are subject to standards of performance under section 113. Available information indicates that these pollution agents are generally emitted from the stationary sources that would be subject to performance standards.

The Committee recognizes that the timing of the control of such pollution agents should be left to the discretion of the Secretary. It is

expected that knowledge with respect to some selected pollution agents would justify immediate application of emission standards, while knowledge with respect to others may not justify the same urgency. Therefore, the bill would establish a framework which would provide that the Secretary may initiate the development of emission standards for such selected pollution agents at any time following the date of enactment. In any event, the Secretary would be required to publish an initial list of agents for which a control under this authority is appropriate within 180 days after enactment of this section. It is expected that the Secretary would select for earliest action those agents on the list which clearly affect the public health. The Committee intends that the Secretary establish a sequence for the setting of emission standards for the remainder over the next several years.

However, the Committee emphasizes that some pollution agents included in this list could become subject to the ambient air quality standards or hazardous substances provisions when new information is developed.

Emission standards developed under this section would be applied to existing stationary sources. However, the Committee recognizes that certain old facilities may use equipment and processes which are not suited to the application of control technology. The Secretary would be authorized therefore to waive the application of standards established under this section to such stationary sources which have short life expectancies after requiring the application of the maximum technology which could be applied to such facilities and after determining that continued emissions would not jeopardize public health.

The bill would provide that emission standards established under this section shall become effective on a date specified but not to exceed 24 months from the date of such promulgation.

Consistent with the provisions of other sections, owners and operators of stationary sources to which emission standards would apply would be responsible for furnishing information relating to emissions, and be required to install, use and maintain monitoring equipment for the purpose of determining compliance with emissions standards. Costs of such monitoring equipment or methods should be borne by the owner or operator.

In this section the bill also would incorporate provisions designed to acquire and make available to the public information regarding compliance with the applicable emission standards. The Committee believes that the public right to know what is being emitted overrides the proprietary character of such information. The committee intends that information other than emission data should be confidential only after a showing by the owners and operators that such records, reports or information would divulge trade secrets or secret processes entitled to protection under section 1905 of Title 18 of the United States Code.

The bill would provide that violations of emission standards established under this section be enforced through the general enforcement provisions of section 116. However, it is provided that the Secretary should delegate enforcement authority to any State which develops an enforcement framework which the Secretary determines adequate to implement the purposes of this section. It should be noted that nothing in such delegation shall in any way effect the Secretary's authority and obligation to act at any time to enforce violations of such emission standards.

SECTION 115. EMISSION STANDARDS FOR HAZARDOUS AGENTS

The proposed new section 115 would authorize the Secretary to prohibit emissions or to establish standards applicable to emissions of air pollutants "whose presence, chronically or intermittently, in trace concentrations in the ambient air, either alone or in combination with other agents, causes or will cause, or contribute to, an increase in mortality or an increase in serious irreversible or incapacitating reversible damage to health."

On the basis of information presented to the Committee, it is clear that the above definition will encompass a limited number of pollutants. Asbestos, cadmium, mercury, and beryllium have been identified as pollution agents which could be subject to emission prohibitions or standards to be established under section 115. It would be the Secretary's responsibility to determine whether there are additional pollutants (including any of those expected to be subject to section 114) which also should be covered under section 115.

In writing a relatively restrictive definition of hazardous agents, the Committee recognized that a total prohibition on emissions is a step that ought to be taken only where a danger to health, as defined, exists. It should be noted that emission standards for pollutants which cannot be considered hazardous (as defined in section 115) could be established under section 114. Thus, there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.

This section would establish an administrative procedure to regulate and control the emission of such hazardous materials. Under this procedure, the Secretary would be authorized to designate from time to time those air pollution agents or combinations of agents which present a hazard to the health of persons as indicated by available material evidence. Following designation the Secretary would be required to publish a proposed prohibition of emissions of such agents or combination of such agents from any stationary source.

The Committee recognizes that some of these hazardous pollutants, such as cadmium and beryllium, are present in nearly all raw materials. Thus, beryllium and cadmium appear as trace impurities in steel making and other raw material processes, in addition to the processing at beryllium and cadmium plants. Recognizing that complete control of beryllium from steel plants, for example, may not be necessary or practicable, the Committee has provided the Secretary with authority to differentiate among categories of sources in establishing prohibitions under section 115.

After public hearings and within six months of the publication of such proposed prohibition, the Secretary would be required to promulgate such prohibition, unless he found on the basis of a preponderance of the evidence, that the air pollution agent was not, in fact, hazardous to the health of persons—or that a greater than zero emission could be permitted without presenting a hazard to health.

The bill would provide that any prohibition should become effective upon promulgation and that any emission standard for a hazardous substance established under this section should become effective no later than 180 days after such promulgation.

The Committee recognizes that the violation of a prohibition or emission standard for any substance which is hazardous to the health of persons requires an expeditious enforcement procedure. Conse-

quently, the bill would provide that upon evidence of any violation the Secretary should bring suit for immediate abatement, including a permanent or temporary injunction or restraining order, in the United States District Court in the District in which the source is located.

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER C—AIR PROGRAMS

[FRL 437-4]

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

State Plans for the Control of Certain Pollutants From Existing Facilities

On October 7, 1974 (39 FR 36102), EPA proposed to add a new Subpart B to Part 60 to establish procedures and requirements for submittal of State plans for control of certain pollutants from existing facilities under section 111(d) of the Clean Air Act, as amended (42 U.S.C. 1857c-6(d)). Interested persons participated in the rulemaking by sending comments to EPA. A total of 45 comment letters was received, 19 of which came from industry, 16 from State and local agencies, 5 from Federal agencies, and 5 from other interested parties. All comments have been carefully considered, and the proposed regulations have been reassessed. A number of changes suggested in comments have been made, as well as changes developed within the Agency.

One significant change, discussed more fully below, is that different procedures and criteria will apply to submittal and approval of State plans where the Administrator determines that a particular pollutant may cause or contribute to the endangerment of public welfare, but that adverse effects on public health have not been demonstrated. Such a determination might be made, for example, in the case of a pollutant that damages crops but has no known adverse effect on public health. This change is intended to allow States more flexibility in establishing plans for the control of such pollutants than is provided for plans involving pollutants that may affect public health.

Most other changes were of a relatively minor nature and, aside from the change just mentioned, the basic concept of the regulations is unchanged. A number of provisions have been reworded to resolve ambiguities or otherwise clarify their meaning, and some were combined or otherwise reorganized to clarify and simplify the overall organization of Subpart B.

Background

When Congress enacted the Clean Air Amendments of 1970, it addressed three general categories of pollutants emitted from stationary sources. See Senate Report No. 91-1196, 91st Cong., 2d Sess. 18-19 (1970). The first category consists of pollutants (often referred to as "criteria pollutants") for which air quality criteria and national ambient air quality standards are established under sections 108 and 109 of the Act. Under the 1970 amendments, criteria pollutants are controlled by State implementation plans (SIP's) approved or promulgated under section 110 and, in some cases, by standards of performance for new sources established under section 111. The second category consists of pollutants listed as hazardous pollutants under section 112 and controlled under that section.

The third category consists of pollutants that are (or may be) harmful to public health or welfare but are not or cannot be controlled under sections 108-110 or 112. Section 111(d) requires control of existing sources of such pollutants whenever standards of performance (for those pollutants) are established under section 111(b) for new sources of the same type.

In determining which statutory approach is appropriate for regulation of a particular pollutant, EPA considers the nature and severity of the pollutant's effects on public health or welfare, the number and nature of its sources, and similar factors prescribed by the Act. Where a choice of approaches is presented, the regulatory advantages and disadvantages of the various options are also considered. As indicated above, section 111(d) requires control of existing sources of a pollutant if a standard of performance is established for new sources under section 111(b) and the pollutant is not controlled under sections 108-110 or 112. In general, this means that control under section 111(d) is appropriate when the pollutant may cause or contribute to endangerment of public health or welfare but is not known to be "hazardous" within the meaning of section 112 and is not controlled under sections 108-110 because, for example, it is not emitted from "numerous or diverse" sources as required by section 108.

For ease of reference, pollutants to which section 111(d) applies as a result of the establishment of standards of performance for new sources are defined in § 60.21(a) of the new Subpart B as "designated pollutants." Existing facilities which emit designated pollutants and which would be subject to the standards of performance for those pollutants, if new, are defined in § 60.21(b) as "designated facilities."

As indicated previously, the proposed regulations have been revised to allow States more flexibility in establishing plans where the Administrator determines that a designated pollutant may cause or contribute to endangerment of public welfare, but that adverse effects on public health have not been demonstrated. For convenience of discussion, designated pollutants for which the Administrator makes such a determination are referred to in this preamble as "welfare-related pollutants" (i.e., those requiring control solely because of their effects on public welfare). All other designated pollutants are referred to as "health-related pollutants."

To date, standards of performance have been established under section 111 of the Act for two designated pollutants—fluorides emitted from five categories of sources in the phosphate fertilizer industry (40 FR 33152, August 6, 1975) and sulfuric acid mist emitted from sulfuric acid production units (36 FR 24877, December 23, 1971). In addition, standards of performance have been proposed for fluorides emitted from primary aluminum plants (39 FR 37730, October 23, 1974), and final action on these standards will occur shortly. EPA will publish draft guideline documents (see next section) for these pollutants in the near future. Although a final decision has not been made, it is expected that sulfuric acid mist will be determined to be a health-related pollutant and that fluorides will be determined to be welfare-related.

Summary of Regulations

Subpart B provides that after a standard of performance applicable to emissions of a designated pollutant from new sources is promulgated, the Administrator will publish guideline documents containing information pertinent to control of the same pollutant from designated (i.e., existing) facilities [§ 60.22(a)]. The guideline documents will include "emission guidelines" (discussed below) and compliance times based on factors specified in § 60.22(b)(5) and will be made available for public comment in draft form before being published in final form. For health-related pollutants, the Administrator will concurrently propose and subsequently promulgate the emission guidelines and compliance times referred to above [§ 60.22(c)]. For welfare-related pollutants, emission guidelines and compliance times will appear only in the applicable guideline documents [§ 60.22(d)(1)].

The Administrator's determination that a designated pollutant is heath-related, welfare-related, or both and the rationale for the determination will be provided in the draft guideline document for that pollutant. In making this determination, the Administrator will consider such factors as: (1) Known and suspected effects of the pollutant on public health and welfare; (2) potential ambient concentrations of the pollutant; (3) generation of any secondary pollutants for which the designated pollutant may be a precursor; (4) any synergistic effect with other pollutants; and (5) potential effects from accumulation in the environment (e.g., soil, water and food chains). After consideration of comments and other information a final determination and rationale will be published in the final guidelines document.

For both health-related and welfare-related pollutants, emission guidelines will reflect the degree of control attainable with the application of the best systems of emission reduction which (considering the cost of such reduction) have been adequately demonstrated for designated facilities [§ 60.21(e)]. As discussed more fully below, the degree of control reflected in EPA's emission guidelines will take into account the costs of retrofitting existing facilities and thus will probably be less stringent than corresponding standards of performance for new sources.

After publication of a final guideline document for a designated pollutant, the States will have nine months to develop

and submit plans containing emission standards for control of that pollutant from designated facilities [§ 60.23(a)]. For health-related pollutants, State emission standards must ordinarily be at least as stringent as the corresponding EPA guidelines to be approvable [§ 60.24 (c)]. However, States may apply less stringent standards to particular sources (or classes of sources) when economic factors or physical limitations specific to particular sources (or classes of sources) make such application significantly more reasonable [§ 60.24(f)]. For welfare-related pollutants, States may balance the emission guidelines and other information provided in EPA's guideline documents against other factors of public concern in establishing their emission standards, provided that appropriate consideration is given to the information presented in the guideline documents and at public hearings and that other requirements of Subpart B are met [§ 60.24(d)].

Within four months after the date required for submission of a plan, the Administrator will approve or disapprove the plan or portions thereof [§ 60.27(b)]. If a State plan (or portion thereof) is disapproved, the Administrator will promulgate a plan (or portion thereof) within 6 months after the date required for plan submission [§ 60.27(d)]. The plan submittal, approval/disapproval, and promulgation procedures are basically patterned after section 110 of the Act and 40 CFR Part 51 (concerning adoption and submittal of State implementation plans under section 110).

For health-related pollutants, the emission guidelines and compliance times referred to above will appear in a new Subpart C of Part 60. As indicated previously, emission guidelines and compliance times for welfare-related pollutants will appear only in the guideline documents published under § 60.22(a). Approvals and disapprovals of State plans and any plans (or portions thereof) promulgated by the Administrator will appear in a new Part 62.

Comments Received on Proposed Regulations and Changes Made in Final Regulations

Many of the comment letters received by EPA contained multiple comments. The most significant comments and differences between the proposed and final regulations are discussed below. Copies of the comment letters and a summary of the comments with EPA's responses (entitled "Public Comment Summary: Section 111(d) Regulations") are available for public inspection and copying at the EPA Public Information Reference Unit, Room 2922 (EPA Library), 401 M Street, SW., Washington, D.C. 20460. In addition, copies of the comment summary may be obtained upon written request from the EPA Public Information Center (PM–215), 401 M Street, SW., Washington, D.C. 20460 (specify "Public Comment Summary: Section 111(d) Regulations").

(1) *Definitions and basic concepts.* The term "emission limitation" as defined in proposed § 60.21(e) has apparently caused some confusion. As used in the proposal, the term was not intended to mean a legally enforceable national emission standard as some comments suggested. Indeed, the term was chosen in an attempt to avoid such confusion. EPA's rationale for using the emission limitation concept is presented below in the discussion of the basis for approval or disapproval of State plans. However, to emphasize that a legally enforceable standard is not intended, the term "emission limitation" has been replaced with the term "emission guideline" [see § 60.21(e)]. In addition, proposed § 60.27 (concerning publication of guideline documents and so forth) has been moved forward in the regulations (becoming § 60.22) to emphasize that publication of a final guideline document is the "trigger" for State action under subsequent sections of Subpart B [see § 60.23(a)].

Many commentators apparently confused the degree of control to be reflected in EPA's emission guidelines under section 111(d) with that to be required by corresponding standards of performance for new sources under section 111(b). Although the general principle (application of best adequately demonstrated control technology, considering costs) will be the same in both cases, the degrees of control represented by EPA's emission guidelines will ordinarily be less stringent than those required by standards of performance for new sources because the costs of controlling existing facilities will ordinarily be greater than those for control of new sources. In addition, the regulations have been amended to make clear that the Administrator will specify different emission guidelines for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, and similar factors make subcategorization appropriate [§ 60.22(b)(5)]. Thus, while there may be only one standard of performance for new sources of designated pollutants, there may be several emission guidelines specified for designated facilities based on plant configuration, size, and other factors peculiar to existing facilities.

Some comments evidenced confusion regarding the relationship of affected facilities and designated facilities. An affected facility, as defined in § 60.2(e), is a new or modified facility subject to a standard of performance for new stationary sources. An existing facility [§ 60.2(aa)] is a facility of the same type as an affected facility, but one the construction of which commenced before the date of proposal of applicable standards of performance. A designated facility [§ 60.21(d)] is an existing facility which emits a designated pollutant.

A few industry comments argued that the proposed regulations would permit EPA to circumvent the legal and technical safeguards required under sections 108, 109, and 110 of the Act, sections which the commentators characterized as the basic statutory process for control of existing facilities. Congress clearly intended control of existing facilities under sections other than 108, 109, and 110. Sections 112 and 303 as well as 111(d) itself provide for control of existing facilities. Moreover, action under section 111(d) is subject to a number of significant safeguards: (1) Before acting under section 111(d) the Administrator must have found under section 111(b) that a source category may significantly contribute to air pollution which causes or contributes to the endangerment of public health or welfare, and this finding must be technically supportable; (2) EPA's emission guidelines will be developed in consultation with industrial groups and the National Air Pollution Control Techniques Advisory Committee, and they will be subject to public comment before they are adopted; (3) emission standards and other plan provisions must be subjected to public hearings prior to adoption; (4) relief is available under § 60.24(f) or § 60.27(e)(2) where application of emission standards to particular sources would be unreasonable; and (5) judicial review of the Administrator's action in approving or promulgating plans (or portions thereof) is available under section 307 of the Act.

A number of commentators suggested that special provisions for plans submitted under section 111(d) are unnecesssary since existing facilities are covered by State implementation plans (SIPs) approved or promulgated under section 110 of the Act. By its own terms, however, section 111(d) requires the Administrator to prescribe regulations for section 111(d) plans. In addition, the pollutants to which section 111(d) applies (i.e., designated pollutants) are not controlled as such under the SIPs. Under section 110, the SIPs only regulate criteria pollutants; i.e., those for which national ambient air quality standards have been established under section 109 of the Act. By definition, designated pollutants are non-criteria pollutants [§ 60.21(a)]. Although some designated pollutants may occur in particulate as well as gaseous forms and thus may be controlled to some degree under SIP provisions requiring control of particulate matter, specific rather than incidental control of such pollutants is required by section 111(d). For these reasons, separate regulations are necessary to establish the framework for specific control of designated pollutants under section 111(d).

Comments of a similar nature argued that if there are demonstrable health and welfare effects from designated pollutants, either air quality criteria should be established and SIPs submitted under sections 108–110 of the Act, or the provisions of section 112 of the Act should be applied. Section 111(d) of the Act was specifically designed to require control of pollutants which are not presently considered "hazardous" within the meaning of section 112 and for which ambient air quality standards have not been promulgated. Health and welfare effects from these designated pollutants often cannot be quantified or are of such a nature that the effects are cumulative and not associated with any particular

ambient level. Quite often, health and welfare problems caused by such pollutants are highly localized and thus an extensive procedure, such as the SIPs require, is not justified. As previously indicated, Congress specifically recognized the need for control of a third category of pollutants; it also recognized that as additional information becomes available, these pollutants might later be reclassified as hazardous or criteria pollutants.

Other commentators reasoned that since designated pollutants are defined as non-criteria and non-hazardous pollutants, only harmless substances would fall within this category. These commentators argued that the Administrator should establish that a pollutant has adverse effects on public health or welfare before it could be regulated under section 111(d). Before acting under section 111(d), however, the Administrator must establish a standard of performance under section 111(b). In so doing, the Administrator must find under section 111(b) that the source category covered by such standards may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare.

(2) *Basis for approval or disapproval of State plans.* A number of industry comments questioned EPA's authority to require, as a basis for approval of State plans, that the States establish emission standards that (except in cases of economic hardship) are equivalent to or more stringent than EPA's emission guidelines. In general, these comments argued that EPA has authority only to prescribe procedural requirements for adoption and submittal of State plans, leaving the States free to establish emission standards on any basis they deem necessary or appropriate. Most State comments expressed no objection to EPA's interpretation on this point, and a few explicitly endorsed it.

After careful consideration of these comments, EPA continues to believe, for reasons summarized below, that its interpretation of section 111(d) is legally correct. Moreover, EPA believes that its interpretation is essential to the effective implementation of section 111(d), particularly where health-related pollutants are involved. As discussed more fully below, however, EPA has decided that it is appropriate to allow States somewhat more flexibility in establishing plans for the control of welfare-related pollutants and has revised the proposed regulations accordingly.

Although section 111(d) does not specify explicit criteria for approval or disapproval of State plans, the Administrator must disapprove plans that are not "satisfactory" [Section 111(d)(2)(A)]. Appropriate criteria must therefore be inferred from the language and context of section 111(d) and from its legislative history. It seems clear, for example, that the Administrator must disapprove plans not adopted and submitted in accordance with the procedural requirements he prescribes under section 111(d), and none of the commentators questioned this concept. The principal questions, therefore, are whether Congress intended that the Administrator base approvals and disapprovals on substantive as well as procedural criteria and, if so, on what types of substantive criteria.

A brief summary of the legislative history of section 111(d) will facilitate discussion of these questions. Section 111(d) was enacted as part of the Clean Air Amendments of 1970. No comparable provision appeared in the House bill. The Senate bill, however, contained a section 114 that would have required the establishment of national emission standards for "selected air pollution agents." Although the term "selected air pollution agent" did not include pollutants that might affect public welfare [which are subject to control under section 111(d)], its definition otherwise corresponded to the description of pollutants to be controlled under section 111(d). Section 114 of the Senate bill was rewritten in conference to become section 111(d). Although the Senate report and debates include references to the intent of section 114, neither the conference report nor subsequent debates include any discussion of section 111(d) as finally enacted. In the absence of such discussion, EPA believes inferences concerning the legislative intent of section 111(d) may be drawn from the general purpose of section 114 of the Senate bill and from the manner in which it was rewritten in conference.

After a careful examination of section 111(d), its statutory context, and its legislative history, EPA believes the following conclusions may be drawn:

(1) As appears from the Senate report and debates, section 114 of the Senate bill was designed to address a specific problem. That problem was how to reduce emissions of pollutants which are (or may be) harmful to health but which, on the basis of information likely to be available in the near term, cannot be controlled under other sections of the Act as criteria pollutants or as hazardous pollutants. (It was made clear that such pollutants might be controlled as criteria or hazardous pollutants as more definitive information became available.) The approach taken in section 114 of the Senate bill was to require national emission standards designed to assure that emissions of such pollutants would not endanger health.

(2) The Committee of Conference chose to rewrite the Senate provision as part of section 111, which in effect requires maximum feasible control of pollutants from new stationary sources through technology-based standards (as opposed to standards designed to assure protection of health or welfare or both). For reasons summarized below, EPA believes this choice reflected a decision in conference that a similar approach (making allowances for the costs of controlling existing sources) was appropriate for the pollutants to be controlled under section 111(d).

(3) As reflected in the Senate report and debates, the pollutants to be controlled under section 114 of the Senate bill were considered a category distinct from the pollutants for which criteria documents had been written or might soon be written. In part, these pollutants differed from the criteria pollutants in that much less information was available concerning their effects on public health and welfare. For that reason, it would have been difficult—if not impossible—to prescribe legally defensible standards designed to protect public health or welfare for these pollutants until more definitive information became available. Yet the pollutants, by definition, were those which (although not criteria pollutants and not known to be hazardous) had or might be expected to have adverse effects on health.

(4) Under the circumstances, EPA believes, the conferees decided (a) that control of such pollutants on some basis was necessary; (b) that, given the relative lack of information on their health and welfare effects, a technology-based approach (similar to that for new sources) would be more feasible than one involving an attempt to set standards tied specifically to protection of health; and (c) that the technology-based approach (making allowances for the costs of controlling existing sources) was a reasonable means of attacking the problem until more definitive information became known, particularly because the States would be free under section 116 of the Act to adopt more stringent standardse if they believed additional control was desirable. In short, EPA believes the conferees chose to rewrite section 114 as part of section 111 largely because they intended the technology-based approach of that section to extend (making allowances for the costs of controlling existing sources) to action under section 111(d). In this view, it was unnecessary (although it might have been desirable) to specify explicit substantive criteria in section 111(d) because the intent to require a technology-based approach could be inferred from placement of the provision in section 111.

Related considerations support this interpretation of section 111(d). For example, section 111(d) requires the Administrator to prescribe a plan for a State that fails to submit a satisfactory plan. It is obvious that he could only prescribe standards on some substantive basis. The references to section 110 of the Act suggest that (as in section 110) he was intended to do generally what the States in such cases should have done, which in turn suggests that (as in section 110) Congress intended the States to prescribe standards on some substantive basis. Thus, it seems clear that some substantive criterion was intended to govern not only the Administrator's promulgation of standards but also his review of State plans.

Still other considerations support EPA's interpretation of section 111(d). Even a cursory examination of the legislative history of the 1970 amendments reveals that Congress was dissatisfied with air pollution control efforts at all levels

of government and was convinced that relatively drastic measures were necessary to protect public health and welfare. The result was a series of far-reaching amendments which, coupled with virtually unprecedented statutory deadlines, required EPA and the States to take swift and aggressive action. Although Congress left initial responsibility with the States for control of criteria pollutants under section 110, it set tough minimum criteria for such action and required Federal assumption of responsibility where State action was inadequate. It also required direct Federal action for control of new stationary sources, hazardous pollutants, and mobile sources. Finally, in an extraordinary departure from its practice of delegating rulemaking authority to administrative agencies (a departure intented to force the pace of pollution control efforts in the automobile industry), Congress itself enacted what amounted to statutory emission standards for the principal automotive pollutants.

Against this background of Congressional firmness, the overriding purpose of which was to protect public health and welfare, it would make no sense to interpret section 111(d) as requiring the Administrator to base approval or disapproval of State plans solely on procedural criteria. Under that interpretation, States could set extremely lenient standards—even standards permitting greatly increased emissions—so long as EPA's procedural requirements were met. Given that the pollutants in question are (or may be) harmful to public health and welfare, and that section 111(d) is the only provision of the Act requiring their control, it is difficult to believe that Congress meant to leave such a gaping loophole in a statutory scheme otherwise designed to force meaningful action.

Some of the comments on the proposed regulations assume that the States were intended to set emission standards based directly on protection of public health and welfare. EPA believes this view is consistent with its own view that the Administrator was intended to base approval or disapproval of State plans on substantive as well as procedural criteria but believes Congress intended a technology-based approach rather than one based directly on protection of health and welfare. The principal factors leading EPA to this conclusion are summarized above. Another is that if Congress had intended an approach based directly on protection of health and welfare, it could have rewritten section 114 of the Senate bill as part of section 110, which epitomizes that approach, rather than as part of section 111. Indeed, with relatively minor changes in language, Congress could simply have retained section 114 as a separate section requiring action based directly on protection of health and welfare.

Still another factor is that asking each of the States, many of which had limited resources and expertise in air pollution control, to set standards protective of health and welfare in the absence of adequate information would have made even less sense than requiring the Administrator to do so with the various resources at his command. Requiring a technology-based approach, on the other hand, would not only shift the criteria for decision-making to more solid ground (the availability and costs of control technology) but would also take advantage of the information and expertise available to EPA from its assessment of techniques for the control of the same pollutants from the same types of sources under section 111(b), as well as its power to compel submission of information about such techniques under section 114 of the Act (42 U.S.C. 1857c–9). Indeed, section 114 was made specifically applicable for the purpose (among others) of assisting in the development of State plans under section 111(d). For all of these reasons, EPA believes Congress intended a technology-based approach rather than one based directly on protection of health and welfare.

Some of the comments argued that EPA's emission guidelines under section 111(d) will, in effect, be national emission standards for existing sources, a concept they argue was rejected in section 111(d). In general, the comments rely on the fact that although section 114 of the Senate bill specifically provided for national emission standards, section 111(d) calls for establishment of emission standards by States. EPA believes that the rewriting of section 114 in conference is consistent with the establishment of national criteria by which to judge the adequacy of State plans, and that the approach taken in section 111(d) may be viewed as largely the result of two decisions: (1) To adopt a technology-based approach similar to that for new sources; and (2) to give States a greater role than was provided in section 114. Thus, States will have primary responsibility for developing and enforcing control plans under section 111(d); under section 114, they would only have been invited to seek a delegation of authority to enforce Federally developed standards. Under EPA's interpretation of section 111(d), States will also have authority to grant variances in cases of economic hardship; under section 114, only the Administrator would have had authority to grant such relief. As with section 110, assigning primary responsibility to the States in these areas is perfectly consistent with review of their plans on some substantive basis. If there is to be substantive review, there must be criteria for the review, and EPA believes it is desirable (if not legally required) that the criteria be made known in advance to the States, to industry, and to the general public. The emission guidelines, each of which will be subjected to public comment before final adoption, will serve this function.

In any event, whether or not Congress "rejected" the concept of national emission standards for existing sources, EPA's emission guidelines will not have the purpose or effect of national emission standards. As emphasized elsewhere in this preamble, they will not be requirements enforceable against any source. Like the national ambient air quality standards prescribed under section 109 and the items set forth in section 110(a)(2)(A)–(H), they will only be criteria for judging the adequacy of State plans.

Moreover, it is inaccurate to argue (as did one comment) that, because EPA's emission guidelines will reflect best available technology considering cost, States will be unable to set more stringent standards. EPA's emission guidelines will reflect its judgment of the degree of control that can be attained by various classes of existing sources without unreasonable costs. Particular sources within a class may be able to achieve greater control without unreasonable costs. Moreover, States that believe additional control is necessary or desirable will be free under section 116 of the Act to require more expensive controls, which might have the effect of closing otherwise marginal facilities, or to ban particular categories of sources outright. Section 60.24(g) has been added to clarify this point. On the other hand, States will be free to set more lenient standards, subject to EPA review, as provided in §§ 60.24(d) and (f) in the case of welfare-related pollutants and in cases of economic hardship.

Finally, as discussed elsewhere in this preamble, EPA's emission guidelines will reflect subcategorization within source categories where appropriate, taking into account differences in sizes and types of facilities and similar considerations, including differences in control costs that may be involved for sources located in different parts of the country. Thus, EPA's emission guidelines will in effect be tailored to what is reasonably achievable by particular classes of existing sources, and States will be free to vary from the levels of control represented by the emission guidelines in the ways mentioned above. In most if not all cases, the result is likely to be substantial variation in the degree of control required for particular sources, rather than identical standards for all sources.

In summary, EPA believes section 111(d) is a hybrid provision, intended to combine primary State responsibility for plan development and enforcement (as in section 110) with the technology-based approach (making allowances for the costs of controlling existing sources) taken in section 111 generally. As indicated above, EPA believes its interpretation of section 111(d) is legally correct in view of the language, statutory context, and legislative history of the provision.

Even assuming some other interpretation were permissible, however, EPA believes its interpretation is essential to the effective implementation of section 111(d), particularly where health-related pollutants are involved. Most of the reasons for this conclusion are discussed above, but it may be useful to summarize them here. Given the relative lack of information concerning the effects of designated pollutants on public health and welfare, it would be

difficult—if not impossible—for the States or EPA to prescribe legally defensible standards based directly on protection of health and welfare. By contrast, a technology-based approach takes advantage of the information and expertise available to EPA from its assessment of techniques for the control of the same pollutants from the same types of sources under section 111(b), as well as EPA's power to compel submission of information about such techniques under section 114 of the Act. Given the variety of circumstances that may be encountered in controlling existing as opposed to new sources, it makes sense to have the States develop plans based on technical information provided by EPA and make judgments, subject to EPA review, concerning the extent to which less stringent requirements are appropriate. Finally, EPA review of such plans for their substantive adequacy is essential (particularly for health-related pollutants) to assure that meaningful controls will be imposed. For these reasons, given a choice of permissible interpretations of section 111(d), EPA would choose the interpretation on which Subpart B is based on the ground that it is essential to the effective implementation of the provision, particularly where health-related pollutants are involved.

As indicated previously, however, EPA has decided that it is appropriate to allow the States more flexibility in establishing plans for the control of welfare-related pollutants than is provided for plans involving health-related pollutants. Accordingly, the proposed regulations have been revised to provide that States may balance the emission guidelines, compliance times and other information in EPA's guideline documents against other factors in establishing emission standards, compliance schedules, and variances for welfare-related pollutants, provided that appropriate consideration is given to the information presented in the guideline documents and at public hearings, and that all other requirements of Subpart B are met [§ 60.24(d)]. Where sources of pollutants that cause only adverse effects to crops are located in nonagricultural areas, for example, or where residents of a local community depend on an economically marginal plant for their livelihood, such factors could be taken into account. Consistent with section 116 of the Act, of course, States will remain free to adopt requirements as stringent as (or more stringent than) the corresponding emission guidelines and compliance times specified in EPA's guideline documents if they wish [see § 60.24(g)].

A number of factors influenced EPA's decision to allow States more flexibility in establishing plans for control of welfare-related pollutants than is provided for plans involving health-related pollutants. The dominant factor, of course, is that effects on public health would not be expected to occur in such cases, even if State plans required no greater controls than are presently in effect. In a sense, allowing the States greater latitude in such cases simply reflects EPA's view (stated in the preamble to the proposed regulations) that requiring maximum feasible control of designated pollutants may be unreasonable in some situations. Although pollutants that cause only damage to vegetation, for example, are subject to control under section 111(d), few would argue that requiring maximum feasible control is as important for such pollutants as it is for pollutants that endanger public health.

This fundamental distinction—between effects on public health and effects on public welfare—is reflected in section 110 of the Act, which requires attainment of national air quality standards that protect public health within a certain time (regardless of economic and social consequences) but requires attainment of national standards that protect public welfare only within "a reasonable time." The significance of this distinction is reflected in the legislative history of section 110; and the legislative history of section 111(d), although inconclusive, suggests that its primary purpose was to require control of pollutants that endanger public health. For these reasons, EPA believes it is both permissible under section 111(d) and appropriate as a matter of policy to approve State plans requiring less than maximum feasible control of welfare-related pollutants where the States wish to take into account considerations other than technology and cost.

On the other hand, EPA believes section 111(d) requires maximum feasible control of welfare-related pollutants in the absence of such considerations and will disapprove plans that require less stringent control without some reasoned explanation. For similar reasons, EPA will promulgate plans requiring maximum feasible control if States fail to submit satisfactory plans for welfare-related pollutants [§ 60.27(e)(1).] Under § 60.27(e)(2), however, relief will still be available for particular sources where economic hardship can be shown.

(3) *Variances.* One comment asserted that neither the letter nor the intent of section 111 allows variances from plan requirements based on application of best adequately demonstrated control systems. Although section 111(d) does not explicitly provide for variances, it does require consideration of the cost of applying standards to existing facilities. Such a consideration is inherently different than for new sources, because controls cannot be included in the design of an existing facility and because physical limitations may make installation of particular control systems impossible or unreasonably expensive in some cases. For these reasons, EPA believes the provision [§ 60.24(f)] allowing States to grant relief in cases of economic hardship (where health-related pollutants are involved) is permissible under section 111(d). For the same reasons, language has been included in § 60.24(d) to make clear that variances are also permissible where welfare-related pollutants are involved, although the flexibility provided by that provision may make variances unnecessary.

Several commentators urged that proposed § 60.23(e) [now § 60.24(f)] be amended to indicate that States are not required to consider applications for variances if they do not feel it appropriate to do so. The commentators contended that the proposed wording would invite applications for variances, would allow sources to delay compliance by submitting such applications, might conflict with existing State laws, and would probably impose significant burdens on State and local agencies. In addition, there is some question whether the mandatory review provision as proposed would be consistent with section 116 of the Act, which makes clear that States are free to adopt and enforce standards more stringent than Federal standards. Accordingly, the proposed wording has been amended to permit, but not require, State review of facilities for the purpose of applying less stringent standards. To give the States more flexibility, § 60.24(f) has also been amended to permit variances for particular classes of sources as well as for particular sources.

Other comments requested that EPA make clear whether proposed § 60.23(e) [now § 60.24(f)] would allow permanent variances or whether EPA intends ultimate compliance with the emission standards that would apply in the absence of variances. Section 60.24(f) is intended to utilize existing State variance procedures as much as possible. Thus it is up to the States to decide whether less stringent standards are to be applied permanently or whether ultimate compliance will be required.

Another commentator suggested that compliance with or satisfactory progress toward compliance with an existing State emission standard should be a sufficient reason for applying a less stringent standard under § 60.24(f). Such compliance is not necessarily sufficient because existing standards have not always been developed with the intention of requiring maximum feasible control. As indicated in the preamble to the proposed regulations, however, if an existing State emission standard is relatively close to the degree of control that would otherwise be required, and the cost of additional control would be relatively great, there may be justification to apply a less stringent standard under § 60.24(f).

One thoughtful comment suggested that consideration of variances under Subpart B could in effect undermine related SIP requirements; e.g., where designated pollutants occur in particulate forms and are thus controlled to some extent under SIP requirements applicable to particulate matter. Nothing in section 111(d) or Subpart B, however, will preempt SIP requirements. In the event of a conflict, protection of health and welfare under section 110 must control.

(4) *Public hearing requirement.* Based on comments that the requirement for a public hearing on the plan in each AQCR

containing a designated facility is too burdensome, the proposed regulation has been amended to require only one hearing per State per plan. While the Agency advocates public participation in environmental rulemaking, it also recognizes the expense and effort involved in holding multiple hearings. States are urged to hold as many hearings as practicable to assure adequate opportunity for public participation. The hearing requirements have also been amended to provide that a public hearing is not required in those States which have an existing emission standard that was adopted after a public hearing and is at least as stringent as the corresponding EPA emission guidelines, and to permit approval of State notice and hearing procedures different than those specified in Subpart B in some cases.

(5) *Compliance schedules.* The proposed regulation required that all compliance schedules be submitted with the plan. Several commentators suggested that this requirement would not allow sufficient time for negotiation of schedules and could cause duplicative work if the emission standards were not approved. For this reason a new § 60.24 (e) (2) has been added to allow submission of compliance schedules after plan submission but no later than the date of the first semiannual report required by § 60.25(e).

(6) *Existing regulations.* Several comments dealt with States which have existing emission standards for designated pollutants. One commentator urged that such States be exempted from the requirements of adopting and submitting plans. However, the Act requires EPA to evaluate both the adequacy of a State's emission standards and the procedural aspects of the plan. Thus, States with existing regulations must submit plans.

Another commentator suggested that the Administrator should approve existing emission standards which, because they are established on a different basis (e.g., concentration standards vs. process-weight-rate type standards), are more stringent than the corresponding EPA emission guideline for some facilities and less stringent for others. The Agency cannot grant blanket approval for such emission standards; however, the Administrator may approve that part of an emission standard which is equal to or more stringent than the EPA emission guideline and disapprove that portion which is less stringent. Also, the less stringent portions may be approvable in some cases under § 60.24 (d) or (f). Finally, subcategorization by size of source under § 60.22(b) (5) will probably limit the number of cases in which this situation will arise.

Other commentators apparently assumed that some regulations for designated pollutants were approved in the State implementation plans (SIPs). Although some States may have submitted regulations limiting emissions of designated pollutants with the SIPs, such regulations were not considered in the approval or disapproval of those plans and are not considered part of approved plans because, under section 110, SIPs, apply only to criteria pollutants.

(7) *Emission inventory data and reports.* Section 60.24 of the proposed regulations [now § 60.25] required emission inventory data to be submitted on data forms which the Administrator was to specify in the future. It was expected that a computerized subsystem to the National Emission Data System (NEDS) would be available that would accommodate emission inventory information on the designated pollutants. However, since this subsystem and concomitant data form will probably not be developed and approved in time for plan development, the designated pollutant information called for will not be required in computerized data format. Instead, the States will be permitted to submit this information in a non-computerized format as outlined in a new Appendix D along with the basic facility information on NEDS forms (OMB #158–R0095) according to procedures in APTD 1135, "Guide for Compiling a Comprehensive Emission Inventory" available from the Air Pollution Technical Information Center, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. In addition, § 60.25(f) (5) has been amended to require submission of additional information with the semiannual reports in order to provide a better tracking mechanism for emission inventory and compliance monitoring purposes.

(8) *Timing.* Proposed § 60.27(a) required proposal of emission guidelines for designated pollutants simultaneously with proposal of corresponding standards of performance for new (affected) facilities. This section, redesignated § 60.22, has been amended to require proposal (or publication for public comment) of an emission guideline after promulgation of the corresponding standard of performance. Two written comments and several informal comments from industrial representatives indicated that more time was needed to evaluate a standard of performance and the corresponding emission guideline than would be allowed by simultaneous proposal and promulgation. Also, by proposing (or publishing) an emission guideline after promulgation of the corresponding standard of performance, the Agency can benefit from the comments on the standard of performance in developing the emission guideline.

Proposed § 60.27(a) required proposal of sulfuric acid mist emission guidelines within 30 days after promulgation of Subpart B. This provision was included as an exception to the proposed general rule (requiring simultaneous proposal of emission guidelines and standards of performance) because it was impossible to propose the acid mist emission guideline simultaneously with the corresponding standard of performance, which had been promulgated previously. The change in the general rule, discussed above, makes the proposed exception unnecessary, so it has been deleted. As previously stated, the Agency intends to establish emission guidelines for sulfuric acid mist [and for fluorides, for which new source standards were promulgated (40 FR 33152) after proposal of Subpart B] as soon as possible.

(9) *Miscellaneous.* Several commentators argued that the nine months provided for development of State plans after promulgation of an emission guideline by EPA would be insufficient. In most cases, much of the work involved in plan development, such as emission inventories, can be begun when an emission guideline is proposed (or published for comment) by EPA; thus, several additional months will be gained. Extensive control strategies are not required, and after the first plan is submitted, submitted, subsequent plans will mainly consist of adopted emission standards. Section 111(d) plans will be much less complex than the SIPs, and Congress provided only nine months for SIP development. Also, States may already have approvable procedures and legal authority [see §§ 60.25(d) and 60.26(b)], and the number of designated facilities per State should be few. For these reasons, the nine-month provision has been retained.

Some comments recommended that the requirements for adoption and submittal of section 111(d) plans appear in 40 CFR Part 51 or in some part of 40 CFR other than Part 60, to allow differentiation among such requirements, emission guidelines, new source standards and plans promulgated by EPA. The Agency believes that the section 111(d) requirements neither warrant a separate part nor should appear in Part 51, since Part 51 concerns control under section 110 of the Act. For clarity, however, subpart B of Part 60 will contain the requirements for adoption and submittal of section 111(d) plans; Subpart C of Part 60 will contain emission guidelines and times for compliance promulgated under § 60.22 (c); and a new Part 62 will be used for approval or disapproval of section 111(d) and for plans (or portions thereof) promulgated by EPA where State plans are disapproved in whole or in part.

Two comments suggested that the plans should specify test methods and procedures to be used in demonstrating compliance with the emission standards. Only when such procedures and methods are known can the stringency of the emission standard be determined. Accordingly, this change has been included in § 60.24(b).

A new § 60.29 has been added to make clear that the Administrator may revise plan provisions he has promulgated under § 60.27(d), and § 60.27(e) has been revised to make clear that he will consider applications for variances from emission standards promulgated by EPA.

Effective Date. These regulations become effective on December 17, 1975.

(Sections 111, 114, and 301 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91–604, 84 Stat. 1678, and by sec. 15(c)(2) of Pub. L. 91–604, 84 Stat. 1713 (42 U.S.C. 1857c–6, and 1857c–9, 1857g).

Dated: November 5, 1975.

JOHN QUARLES,
Acting Administrator.

Part 60 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. The table of sections for Part 60 is amended by adding a list of sections for Subpart B and by adding Appendix D to the list of appendixes as follows:

* * * * *

Subpart B—Adoption and Submittal of State Plans for Designated Facilities

* * * * *

2. The authority citation at the end of the table of sections for Part 60 is revised to read as follows:

Authority: Secs. 111 and 114 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-6, 1857c-9). Subpart B also issued under sec. 301(a) of the Clean Air Act, as amended by sec. 15(c)(2) of Pub. L. 91-604, 84 Stat. 1713 (42 U.S.C. 1857g).

3. Section 60.1 is revised to read as follows:

§ 60.1 Applicability.

Except as provided in Subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

4. Part 60 is amended by adding Subpart B as follows:

Subpart B—Adoption and Submittal of State Plans for Designated Facilities

§ 60.20 Applicability.

The provisions of this subpart apply to States upon publication of a final guideline document under § 60.22(a).

§ 60.21 Definitions.

Terms used but not defined in this subpart shall have the meaning given them in the Act and in subpart A:

(a) "Designated pollutant" means any air pollutant, emissions of which are subject to a standard of performance for new stationary sources but for which air quality criteria have not been issued, and which is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

(b) "Designated facility" means any existing facility (see § 60.2(aa)) which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility (see § 60.2(e)).

(c) "Plan" means a plan under section 111(d) of the Act which establishes emission standards for designated pollutants from designated facilities and provides for the implementation and enforcement of such emission standards.

(d) "Applicable plan" means the plan, or most recent revision thereof, which has been approved under § 60.27(b) or promulgated under § 60.27(d).

(e) "Emission guideline" means a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22(a), which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities.

(f) "Emission standard" means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, or prescribing equipment specifications for control of air pollution emissions.

(g) "Compliance schedule" means a legally enforceable schedule specifying a date or dates by which a source or category or sources must comply with specific emission standards contained in a plan or with any increments of progress to achieve such compliance.

(h) "Increments of progress" means steps to achieve compliance which must be taken by an owner or operator of a designated facility, including:

(1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency;

(2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.

(3) Initiation of on-site construction or installation of emission control equipment or process change;

(4) Completion of on-site construction or installation of emission control equipment or process change; and

(5) Final compliance.

(i) "Region" means an air quality control region designated under section 107 of the Act and described in Part 81 of this chapter.

(j) "Local agency" means any local governmental agency.

§ 60.22 Publication of guideline documents, emission guidelines, and final compliance times.

(a) After promulgation of a standard of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information pertinent to control of the designated pollutant from designated facilities. Notice of the availability of the draft guideline document will be published in the Federal Register, and public comments on its contents will be invited. After consideration of public comments, a final guideline document will be published and notice of its availability will be published in the Federal Register.

(b) Guideline documents published under this section will provide information for the development of State plans, such as:

(1) Information concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant.

(2) A description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.

(3) Information on the degree of emission reduction which is achievable with each system, together with information on the costs and environmental effects of applying each system to designated facilities.

(4) Incremental periods of time normally expected to be necessary for the design, installation, and startup of identified control systems.

(5) An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

(6) Such other available information as the Administrator determines may contribute to the formulation of State plans.

(c) Except as provided in paragraph (d)(1) of this section, the emission guidelines and compliance times referred to in paragraph (b)(5) of this section will be proposed for comment upon publication of the draft guideline document, and after consideration of comments will be promulgated in Subpart C of this part with such modifications as may be appropriate.

(d)(1) If the Administrator determines that a designated pollutant may cause or contribute to endangerment of public welfare, but that adverse effects on public health have not been demonstrated, he will include the determination in the draft guideline document and in the Federal Register notice of its availability. Except as provided in paragraph (d)(2) of this section, paragraph (c) of this section shall be inapplicable in such cases.

(2) If the Administrator determines at any time on the basis of new information that a prior determination under paragraph (d)(1) of this section is incorrect or no longer correct, he will publish notice of the determination in the Federal Register, revise the guideline document as necessary under paragraph (a) of this section, and propose and promulgate emission guidelines and compliance times under paragraph (c) of this section.

§ 60.23 Adoption and submittal of State plans; public hearings.

(a)(1) Within nine months after notice of the availability of a final guideline document is published under § 60.22(a), each State shall adopt and submit to the Administrator, in accordance with § 60.4, a plan for the control of the designated pollutant to which the guideline document applies.

(2) Within nine months after notice of the availability of a final revised guideline document is published as provided in § 60.22(d)(2), each State shall adopt and submit to the Administrator any plan revision necessary to meet the requirements of this subpart.

(b) If no designated facility is located within a State, the State shall submit a letter of certification to that effect to the Administrator within the time specified in paragraph (a) of this section. Such certification shall exempt the State from the requirements of this subpart for that designated pollutant.

(c)(1) Except as provided in paragraphs (c)(2) and (c)(3) of this section, the State shall, prior to the adoption of any plan or revision thereof, conduct one or more public hearings within the State on such plan or plan revision.

(2) No hearing shall be required for any change to an increment of progress in an approved compliance schedule unless the change is likely to cause the facility to be unable to comply with the final compliance date in the schedule.

(3) No hearing shall be required on an emission standard in effect prior to the effective date of this subpart if it was adopted after a public hearing and is at least as stringent as the corresponding emission guideline specified in the applicable guideline document published under § 60.22(a).

(d) Any hearing required by paragraph (c) of this section shall be held only after reasonable notice. Notice shall be given at least 30 days prior to the date of such hearing and shall include:

(1) Notification to the public by prominently advertising the date, time, and place of such hearing in each region affected;

(2) Availability, at the time of public announcement, of each proposed plan or revision thereof for public inspection in at least one location in each region to which it will apply;

(3) Notification to the Administrator;

(4) Notification to each local air pollution control agency in each region to which the plan or revision will apply; and

(5) In the case of an interstate region, notification to any other State included in the region.

(e) The State shall prepare and retain, for a minimum of 2 years, a record of each hearing for inspection by any interested party. The record shall contain, as a minimum, a list of witnesses together with the text of each presentation.

(f) The State shall submit with the plan or revision:

(1) Certification that each hearing required by paragraph (c) of this section was held in accordance with the notice required by paragraph (d) of this section; and

(2) A list of witnesses and their organizational affiliations, if any, appearing at the hearing and a brief written summary of each presentation or written submission.

(g) Upon written application by a State agency (through the appropriate Regional Office), the Administrator may approve State procedures designed to insure public participation in the matters for which hearings are required and public notification of the opportunity to participate if, in the judgment of the Administrator, the procedures, although different from the requirements of this subpart, in fact provide for adequate notice to and participation of the public. The Administrator may impose such conditions on his approval as he deems necessary. Procedures approved under this section shall be deemed to satisfy the requirements of this subpart regarding procedures for public hearings.

§ 60.24 Emission standards and compliance schedules.

(a) Each plan shall include emission standards and compliance schedules.

(b)(1) Emission standards shall prescribe allowable rates of emissions except when it is clearly impracticable. Such cases will be identified in the guideline documents issued under § 60.22. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

(2) Test methods and procedures for determining compliance with the emission standards shall be specified in the plan. Methods other than those specified in Appendix A to this part may be specified in the plan if shown to be equivalent or alternative methods as defined in § 60.2 (t) and (u).

(3) Emission standards shall apply to all designated facilities within the State. A plan may contain emission standards adopted by local jurisdictions provided that the standards are enforceable by the State.

(c) Except as provided in paragraph (f) of this section, where the Administrator has determined that a designated pollutant may cause or contribute to endangerment of public health, emission standards shall be no less stringent than the corresponding emission guideline(s) specified in subpart C of this part, and final compliance shall be required as expeditiously as practicable but no later than the compliance times specified in Subpart C.

(d) Where the Administrator has determined that a designated pollutant may cause or contribute to endangerment of public welfare but that adverse effects on public health have not been demonstrated, States may balance the emission guidelines, compliance times, and other information provided in the applicable guideline document against other factors of public concern in establishing emission standards, compliance schedules, and variances. Appropriate consideration shall be given to the factors specified in § 60.22(b) and to information presented at the public hearing(s) conducted under § 60.23(c).

(e)(1) Any compliance schedule extending more than 12 months from the date required for submittal of the plan shall include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. Increments of progress shall include, where practicable, each increment of progress specified in § 60.21(h) and shall include such additional increments of progress as may be necessary to permit close and effective supervision of progress toward final compliance.

(2) A plan may provide that compliance schedules for individual sources or categories of sources will be formulated after plan submittal. Any such schedule shall be the subject of a public hearing held according to § 60.23 and shall be submitted to the Administrator within 60 days after the date of adoption of the schedule but in no case later than the date prescribed for submittal of the first semiannual report required by § 60.25(e).

(f) On a case-by-case basis for particular designated facilities, or classes of facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the State demonstrates with respect to each such facility (or class of facilities):

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

(g) Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing (1) emission standards more stringent than emission guidelines specified in subpart C of this part or in applicable guideline documents or (2) compliance schedules requiring final compliance at earlier times than those specified in subpart C or in applicable guideline documents.

§ 60.25 Emission inventories, source surveillance, reports.

(a) Each plan shall include an inventory of all designated facilities, including emission data for the designated pollutants and information related to emissions as specified in Appendix D to this part. Such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable emission standards. As used in this subpart, "correlated" means presented in such a manner as to show the relationship between measured or estimated amounts of emissions and the amounts of such emissions,

allowable under applicable emission standards.

(b) Each plan shall provide for monitoring the status of compliance with applicable emission standards. Each plan shall, as a minimum, provide for:

(1) Legally enforceable procedures for requiring owners or operators of designated facilities to maintain records and periodically report to the State information on the nature and amount of emissions from such facilities, and/or such other information as may be necessary to enable the State to determine whether such facilities are in compliance with applicable portions of the plan.

(2) Periodic inspection and, when applicable, testing of designated facilities.

(c) Each plan shall provide that information obtained by the State under paragraph (b) of this section shall be correlated with applicable emission standards (see § 60.25(a)) and made available to the general public.

(d) The provisions referred to in paragraphs (b) and (c) of this section shall be specifically identified. Copies of such provisions shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates:

(i) That the provisions are applicable to the designated pollutant(s) for which the plan is submitted, and

(ii) That the requirements of § 60.26 are met.

(e) The State shall submit reports on progress in plan enforcement to the Administrator on a semiannual basis, commencing with the first full report period after approval of a plan or after promulgation of a plan by the Administrator. The semiannual periods are January 1–June 30 and July 1–December 31. Information required under this paragraph shall be included in the semiannual reports required by § 51.7 of this chapter.

(f) Each progress report shall include:

(1) Enforcement actions initiated against designated facilities during the reporting period, under any emission standard or compliance schedule of the plan.

(2) Identification of the achievement of any increment of progress required by the applicable plan during the reporting period.

(3) Identification of designated facilities that have ceased operation during the reporting period.

(4) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of plan development but began operation during the reporting period.

(5) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(6) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

§ 60.26 Legal authority.

(a) Each plan shall show that the State has legal authority to carry out the plan, including authority to:

(1) Adopt emission standards and compliance schedules applicable to designated facilities.

(2) Enforce applicable laws, regulations, standards, and compliance schedules, and seek injunctive relief.

(3) Obtain information necessary to determine whether designated facilities are in compliance with applicable laws, regulations, standards, and compliance schedules, including authority to require recordkeeping and to make inspections and conduct tests of designated facilities.

(4) Require owners or operators of designated facilities to install, maintain, and use emission monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such facilities; also authority for the State to make such data available to the public as reported and as correlated with applicable emission standards.

(b) The provisions of law or regulations which the State determines provide the authorities required by this section shall be specifically identified. Copies of such laws or regulations shall be submitted with the plan unless:

(1) They have been approved as portions of a preceding plan submitted under this subpart or as portions of an implementation plan submitted under section 110 of the Act, and

(2) The State demonstrates that the laws or regulations are applicable to the designated pollutant(s) for which the plan is submitted.

(c) The plan shall show that the legal authorities specified in this section are available to the State at the time of submission of the plan. Legal authority adequate to meet the requirements of paragraphs (a)(3) and (4) of this section may be delegated to the State under section 114 of the Act.

(d) A State governmental agency other than the State air pollution control agency may be assigned responsibility for carrying out a portion of a plan if the plan demonstrates to the Administrator's satisfaction that the State governmental agency has the legal authority necessary to carry out that portion of the plan.

(e) The State may authorize a local agency to carry out a plan, or portion thereof, within the local agency's jurisdiction if the plan demonstrates to the Administrator's satisfaction that the local agency has the legal authority necessary to implement the plan or portion thereof, and that the authorization does not relieve the State of responsibility under the Act for carrying out the plan or portion thereof.

§ 60.27 Actions by the Administrator.

(a) The Administrator may, whenever he determines necessary, extend the period for submission of any plan or plan revision or portion thereof.

(b) After receipt of a plan or plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator will, within four months after the date required for submission of a plan or plan revision, approve or disapprove such plan or revision or each portion thereof.

(c) The Administrator will, after consideration of any State hearing record, promptly prepare and publish proposed regulations setting forth a plan, or portion thereof, for a State if:

(1) The State fails to submit a plan within the time prescribed;

(2) The State fails to submit a plan revision required by § 60.23(a)(2) within the time prescribed; or

(3) The Administrator disapproves the State plan or plan revision or any portion thereof, as unsatisfactory because the requirements of this subpart have not been met.

(d) The Administrator will, within six months after the date required for submission of a plan or plan revision, promulgate the regulations proposed under paragraph (c) of this section with such modifications as may be appropriate unless, prior to such promulgation, the State has adopted and submitted a plan or plan revision which the Administrator determines to be approvable.

(e)(1) Except as provided in paragraph (e)(2) of this section, regulations proposed and promulgated by the Administrator under this section will prescribe emission standards of the same stringency as the corresponding emission guideline(s) specified in the final guideline document published under § 60.22(a) and will require final compliance with such standards as expeditiously as practicable but no later than the times specified in the guideline document.

(2) Upon application by the owner or operator of a designated facility to which regulations proposed and promulgated under this section will apply, the Administrator may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by this section in accordance with the criteria specified in § 60.24(f).

(f) If a State failed to hold a public hearing as required by § 60.23(c), the Administrator will provide opportunity for a hearing within the State prior to promulgation of a plan under paragraph (d) of this section.

§ 60.28 Plan revisions by the State.

(a) Plan revisions which have the effect of delaying compliance with applicable emission standards or increments of progress or of establishing less stringent emission standards shall be submitted to the Administrator within 60 days after adoption in accordance with the procedures and requirements applicable to development and submission of the original plan.

(b) More stringent emission standards, or orders which have the effect of ac-

celerating compliance, may be submitted to the Administrator as plan revisions in accordance with the procedures and requirements applicable to development and submission of the original plan.

(c) A revision of a plan, or any portion thereof, shall not be considered part of an applicable plan until approved by the Administrator in accordance with this subpart.

§ 60.29 Plan revisions by the Administrator.

After notice and opportunity for public hearing in each affected State, the Administrator may revise any provision of an applicable plan if:

(a) The provision was promulgated by the Administrator, and

(b) The plan, as revised, will be consistent with the Act and with the requirements of this subpart.

5. Part 60 is amended by adding Appendix D as follows:

APPENDIX D—REQUIRED EMISSION INVENTORY INFORMATION

(a) Completed NEDS point source form(s) for the entire plant containing the designated facility, including information on the applicable criteria pollutants. If data concerning the plant are already in NEDS, only that information must be submitted which is necessary to update the existing NEDS record for that plant. Plant and point identification codes for NEDS records shall correspond to those previously assigned in NEDS; for plants not in NEDS, these codes shall be obtained from the appropriate Regional Office.

(b) Accompanying the basic NEDS information shall be the following information on each designated facility:

(1) The state and county identification codes, as well as the complete plant and point identification codes of the designated facility in NEDS. (The codes are needed to match these data with the NEDS data.)

(2) A description of the designated facility including, where appropriate:

(i) Process name.

(ii) Description and quantity of each product (maximum per hour and average per year).

(iii) Description and quantity of raw materials handled for each product (maximum per hour and average per year).

(iv) Types of fuels burned, quantities and characteristics (maximum and average quantities per hour, average per year).

(v) Description and quantity of solid wastes generated (per year) and method of disposal.

(3) A description of the air pollution control equipment in use or proposed to control the designated pollutant, including:

(i) Verbal description of equipment.

(ii) Optimum control efficiency, in percent. This shall be a combined efficiency when more than one device operate in series. The method of control efficiency determination shall be indicated (e.g., design efficiency, measured efficiency, estimated efficiency).

(iii) Annual average control efficiency, in percent, taking into account control equipment down time. This shall be a combined efficiency when more than one device operate in series.

(4) An estimate of the designated pollutant emissions from the designated facility (maximum per hour and average per year). The method of emission determination shall also be specified (e.g., stack test, material balance, emission factor).

(Secs. 111, 114, and 301 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678, and by sec. 15(c)(2) of Pub. L. 91-604, 84 Stat. 1713 (42 U.S.C. 1857c-6, 1857c-9, 1857g))

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TOGETHER WITH

A SECTION-BY-SECTION INDEX

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shall publish proposed regulations, establishing Federal standards of performance for new sources within such category. The Administrator shall afford interested persons an opportunity for written comment on such proposed regulations. After considering such comments, he shall promulgate, within one year after such publication, such standards with such modifications as he deems appropriate. The Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards. Notwithstanding the requirements of the previous sentence, the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such standard. Standards of performance or revisions thereof shall become effective upon promulgation. When implementation and enforcement of any requirement of this Act indicate that emission limitations and percent reductions beyond those required by the standards promulgated under this section are achieved in practice, the Administrator shall, when revising standards promulgated under this section, consider the emission limitations and percent reductions achieved in practice.

(2) The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.

(3) The Administrator shall, from time to time, issue information on pollution control techniques for categories of new sources and air pollutants subject to the provisions of this section.

(4) The provisions of this section shall apply to any new source owned or operated by the United States.

(5) Except as otherwise authorized under subsection (h), nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance.

(6) The revised standards of performance required by enactment of subsection (a)(1)(A) (i) and (ii) shall be promulgated not later than one year after enactment of this paragraph. Any new or modified fossil fuel fired stationary source which commences construction prior to the date of publication of the proposed revised standards shall not be required to comply with such revised standards.

(c)(1) Each State may develop and submit to the Administrator a procedure for implementing and enforcing standards of performance for new sources located in such State. If the Administrator finds the State procedure is adequate, he shall delegate to such State any authority he has under this Act to implement and enforce such standards.

(2) Nothing in this subsection shall prohibit the Administrator from enforcing any applicable standard of performance under this section.

(d)(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 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 108(a) [or emitted from a source category which is regulated under section 112] [or 112(b)] [1] but (ii) to which a standard of performance under this section would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

(2) The Administrator shall have the same authority—

(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 110(c) in the case of failure to submit an implementation plan, and

(B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 113 and 114 with respect to an implementation plan. In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.

(e) After the effective date of standards of performance promulgated under this section, it shall be unlawful for any owner or operator of any new source to operate such source in violation of any standard of performance applicable to such source.

(f)(1) For those categories of major stationary sources that the Administrator listed under subsection (b)(1)(A) before the date of the enactment of the Clean Air Act Amendments of 1990 and for which regulations had not been proposed by the Administrator by such date, the Administrator shall—

(A) propose regulations establishing standards of performance for at least 25 percent of such categories of sources within 2 years after the date of the enactment of the Clean Air Act Amendments of 1990;

(B) propose regulations establishing standards of performance for at least 50 percent of such categories of sources within 4 years after the date of the enactment of the Clean Air Act Amendments of 1990; and

(C) propose regulations for the remaining categories of sources within 6 years after the date of the enactment of the Clean Air Act Amendments of 1990.

(2) In determining priorities for promulgating standards for categories of major stationary sources for the purpose of paragraph (1), the Administrator shall consider—

(A) the quantity of air pollutant emissions which each such category will emit, or will be designed to emit;

[1] The amendments, made by section 108(g) and 302(a) of P.L. 101-549, appear to be duplicative; both, in different language, change the reference to section 112.

EPA-453/R-94-021

AIR EMISSIONS FROM MUNICIPAL SOLID WASTE LANDFILLS - BACKGROUND INFORMATION FOR FINAL STANDARDS AND GUIDELINES

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
December 1995

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Publication No. EPA-453/R-94-021

ENVIRONMENTAL PROTECTION AGENCY

Air Emissions from Municipal Solid Waste Landfills--
Background Information for Final Standards and Guidelines

Prepared by:

_____ _____
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Research Triangle Park, NC 27711

1. The standards of performance and emission guidelines limit emissions from new and existing municipal solid waste landfills that emit over 50 Mg/yr of nonmethane organic compounds (NMOC). Section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, directs the Administrator to establish standards of performance and emission guidelines for any category of source of air pollution that "... causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

2. Copies of this document have been sent to the following Federal Departments: Office of Management and Budget, Commerce, Interior, and Energy; the National Science Foundation; and the Council on Environmental Quality. Copies have also been sent to members of the State and Territorial Air Pollution Program Administrators; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; and other interested parties.

3. For additional information contact:
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4. Copies of this document may be obtained from:
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   Springfield, VA 22161

2.5 million Mg or 2.5 million m^3 are subject to the additional provisions of the standards or guidelines.

Some changes have been made to the definitions in both subpart WWW and subpart Cc so that definitions in these subparts would be consistent with definitions in regulations of part 258 of title 40, Criteria for MSW Landfills Under RCRA.

MSW landfills are also listed under section 112(c) as a source category (57 FR 31576, July 16, 1992). Promulgation of section 112 emission standards for the MSW landfills source category is currently scheduled for not later than November 15, 2000 (58 FR 63941, 63954, Dec. 3, 1993).

Section 111(d)(1)(A) was twice amended by the 1990 Clean Air Act Amendments. Pub. L. 101-549, section 302(a), directed the substitution of "7412(b)" for "7412(b)(1)(A)," and Pub. L. 101-549, section 108(g), substituted "or emitted from a source category which is regulated under section 7412 of this title" for "or 7412(b)(1)(A)." Title 42 of the U.S. Code adopts the amendment of section 108(g) with the explanation that section 302(a) could not be executed because of the prior amendment by section 108(g). 42 U.S.C. section 7411 (Supp.IV 1993). The EPA also believes that section 108(g) is the correct amendment because the Clean Air Act Amendments revised section 112 to include regulation of source categories in addition to regulation of listed hazardous air pollutants, and section 108(g) thus conforms to other amendments of section 112. The section not adopted by title 42, 302(a), on the other hand, is a simple substitution of one subsection citation for another, without consideration of other amendments of the section in which it resides, section 112. Thus EPA agrees that CAA section 111(d)(1)(A) should read "[t]he Administrator shall prescribe regulations which . . . establish[] standards of performance for any existing source

for any air pollutant . . . which is not . . . emitted from a source category which is regulated under section 112."

Thus, as amended by the 1990 Clean Air Act Amendments, section 111(d)(1)(A) allows EPA to establish NSPS without prescribing emission guidelines for existing sources if the designated air pollutant is 1) a pollutant for which air quality criteria have been issued, 2) included on a list published under section 108(a), or 3) emitted from a source category regulated under section 112. That is not the case here because landfill gas, the designated air pollutant for MSW landfills, is not a pollutant which satisfies any of these criteria. First, landfill gas is a composite of many compounds, including some compounds for which air quality criteria have been issued and which are included on a list published under section 108(a) (e.g. volatile organic compounds (VOC), which are ozone precursors), although other landfill gas components, such as methane and methylene chloride, are not compounds for which air quality criteria have been issued and are not included on a list published under section 108(a). Moreover, landfill gas itself is not an air pollutant for which air quality criteria have been issued, and landfill gas itself is not included on a list published under section 108(a).

Finally, landfill gas is not emitted from a source category that is actually being regulated under section 112. Although MSW landfills is a source category listed under section 112(c), existing MSW landfills will not actually be regulated under section 112 until an emission standard is proposed under section 112(d). Because a section 112 emission standard for MSW landfills is not scheduled for promulgation until the year 2000, MSW landfill emissions will not actually be regulated under section 112 until that time. In addition, some components of landfill gas are not hazardous air pollutants listed under section 112(b) and thus will not be

regulated under a section 112(d) emission standard. Therefore, EPA is establishing emission guidelines under section 111(d)(1)(A) for sources of the designated pollutant landfill gas.

1.1.3 Standards for Air Emissions from Municipal Solid Waste Landfills

The final standards and EG for MSW landfill emissions require the periodic calculation of the annual NMOC emission rate at each affected or designated facility with a maximum design capacity greater than or equal to 2.5 million Mg or 2.5 million m^3.

The best demonstrated technology (BDT) (for both the NSPS and the EG) requires the reduction of MSW landfill emissions from new and existing MSW landfills emitting 50 Mg per year (Mg/yr) of NMOC or more with: (1) a well-designed and well-operated gas collection system and (2) a control device capable of reducing NMOC in the collected gas by 98 weight-percent.

A well-designed and well-operated collection system would, at a minimum: (1) be capable of handling the maximum gas generation rate; (2) have a design capable of monitoring and adjusting the operation of the system; (3) be able to collect gas effectively from all areas of the landfill that warrant control; and (4) be able to expand by the addition of further collection system components to collect gas from new areas of the landfill as they require control.

The BDT control device is a combustion device capable of reducing NMOC emissions by 98 weight-percent. While energy recovery is strongly recommended, the cost analysis is based on open flares because they are applicable to all affected and designated facilities regulated by the standards and emissions guidelines. If an owner or operator uses an enclosed combustion device, the device must demonstrate either the 98-percent reduction or reduction of the outlet NMOC

104TH CONGRESS
1st Session

DRAFTING STYLE

HLC
104–1

HOUSE LEGISLATIVE COUNSEL'S MANUAL ON DRAFTING STYLE

NOVEMBER 1995

PREPARED BY

THE OFFICE OF THE LEGISLATIVE COUNSEL

U.S. HOUSE OF REPRESENTATIVES

(ii) EFFECT.—This approach is the opposite of an amendment by restatement because it—

(I) highlights the particular changes made (unless the number of changes are so great as to obscure each change); and

(II) avoids the risks caused by including the unchanged language.

However, cut-and-bite amendments require a side-by-side comparison of the amendments and the existing law in order to understand the effect of the amendments.

(B) ADDITION OF CLARIFYING LANGUAGE.—Frequently a cut-and-bite amendment can be made more understandable by striking (and then reinserting) more material than is technically necessary in cases in which the additional material can provide "context".

(b) SEQUENCE OF AMENDMENTS IN BILLS THAT AMEND STATUTES.—

(1) ORDER OF IMPORTANCE.—Except as noted in paragraphs (2) and (3), amendments to statutes should be set forth in their relative order of impor-

tance or at least in some rational arrangement of subject matter.

(2) GROUPING WITH TECHNICAL AND CONFORMING AMENDMENTS.—Frequently it is advisable to group the technical and conforming amendments with the related principal amendment to improve the organization and facilitate committee or House floor amendments. As an alternative, the technical and conforming amendments may be located in a general technical and conforming section and be grouped and identified, by use of a heading, as relating to the principal amendment.

(3) STRUCTURE OF AMENDED ACT.—If the number of amendments is large, and they are approximately equal in importance, it may be beneficial for the reader to show them according to the numerical sequence of the sections of the Act amended.

(c) AMENDMENT TERMINOLOGY.—

(1) REFERENCE TO MATTER TO BE STRICKEN.—

(A) OMIT DESCRIPTIVE CHARACTERIZATIONS.—Any descriptive characterization of material to be removed (such as "the word . . . ", "the number . . . ", or "the adverbial phrase . . . ") is surplusage if the ma-

terial itself is set forth. Example: "Section 5 of the ABC Act is amended by striking ~~the phrase~~ 'by the Secretary'.".

(B) "METES AND BOUNDS" REFERENCE FOR LONG MATERIAL.—

(i) IDENTIFY BEGINNING AND END.—When faced with removing large portions of language and showing all of it does not aid the reader in understanding the legislation, one should strike the language by identifying its beginning and ending. (The ending or beginning can be implicit if it coincides with the ending or beginning of the unit being amended.)

(ii) EXAMPLES.—

(I) Section 5 of the ABC Act is amended by striking "as determined by the Secretary" and all that follows through "opportunity for public comment".

(II) Section 5 of the ABC Act is amended by striking "as determined by the Secretary" and all that follows.

(III) The 1st sentence of section 5 of the ABC Act is amended by

striking so much of the sentence as precedes paragraph (1) and inserting the following: "The Secretary shall—".

(C) "DOWN".—In referring to a block of material, the "down", as in the following, is surplusage: "The ABC Act is amended by striking 'as determined by the Secretary' and all that follows ~~down~~ through 'opportunity for public comment'.".

(D) "OUT".—The "out" in "strike out" is surplusage.

(E) "IN LIEU THEREOF".—The "in lieu thereof" in "insert in lieu thereof" is surplusage if the insertion is intended to be made where the striking takes place.

(2) INSERTING OR ADDING.—One "inserts" material within the text of a provision and "adds" it if it is placed at the end of the provision involved.

(3) ADDING MATERIAL AFTER CUT-IN PARAGRAPHS.—It may be necessary when amending a section with cut-in paragraphs to make sure that an addition to the end of the section will not be included in the last paragraph but will appear after it. Use the phrase "is amended by adding after and

below [paragraph (1)] the following:" (and be sure to indent it properly).

(4) "IMMEDIATELY".—Avoid using "immediately" to identify where new language is to be placed, since the meaning it intends to provide should already be given by the amendment. Example: "Section 5 of the ABC Act is amended by inserting ~~immediately~~ after 'good faith' the following: ', as determined by the Secretary,'.".

(5) "FOLLOWING".—The term "following" should be as close to the colon as possible. Consequently, the preferable style is "adding at the end the following:", not "adding the following at the end:".

(6) "THEREOF".—The use of "thereof" as part of a description of the matter amended is redundant. Example: "Section 5 is amended by adding at the end ~~thereof~~ the following:".

(7) EACH PLACE RATHER THAN EACH TIME.—In the case of changing a term that appears more than once in a provision, "place" rather than "time" is the more accurate way to refer to the locations of the term. Example: "Section 5 is amended by striking 'X' each ~~time~~ *place* it appears and inserting 'Y'.".

(d) CUMULATIVE AMENDMENTS.—If a series of sections or subdivisions are added sequentially to a provision after the 1st amendment is made, the amendatory language for successive amendments should use 1 of the following formulations:

(1) EXAMPLE 1.—"Title XX is amended by adding after section 123 (as added by section 802 of this Act) the following new section:".

(2) EXAMPLE 2.—"Title XX (as amended by sections 802 and 803 of this Act) is further amended by adding at the end the following:".

(3) EXAMPLE 3.—If there are numerous amendments, "Title XX (as amended by the preceding provisions of this Act) is further amended by adding at the end the following:".

The assumption is that the earlier (preceding) amendments have been executed.

(e) SERIAL AMENDMENTS.—

(1) IN GENERAL.—In lists of amendments of more or less equal importance that are made to the same provision, start with "[Subdivision (x)] is amended—" followed by a cut-in list of items each beginning with "by".

(2) ABUSE OF FORMAT.—The format described in paragraph (1) can be beneficial when its use is

limited to a few items. However, as with any drafting device, it creates befuddlement when it is applied in the extreme. One executive agency produced proposed legislation that began "The United States Code is amended—". This approach would cause substantial Ramseyer problems.[11]

(f) AMENDMENTS TO TABLE OF SECTIONS (AND OTHER TABLES).—The elements of a table of contents, or any other table, are generally referred to as "items" for purposes of amendments or cross references.

(g) MARGIN AND ALIGNMENT AMENDMENTS.—

(1) BY AMENDING TO READ AS FOLLOWS.—A traditional approach for—

(A) converting an unsubdivided subsection (or other provision) into a paragraph solely for purposes of being able to add an additional paragraph;

(B) correcting the margin of a provision; or

(C) moving a provision from 1 location to another;

is to strike the material and reinsert it with the proper margins or indentations and designations. Since this results in the language appearing (even

[11] A "Ramseyer" is a comparative print required by House Rule XIII, cl. 3 (commonly referred to as the "Ramseyer Rule"), to be included in a committee report accompanying legislation that proposes to repeal or amend an existing statute. The comparative print shows the existing statute, with the deletions and insertions proposed by the legislation shown in different typefaces. The common name for this print derives from the original proponent of the comparative print requirement in 1929, Representative C. William Ramseyer of Iowa.

though unchanged), it can create problems during the consideration of the legislation as well as result in the reenactment of the language involved (see subsection (a)(2)).

(2) WITHOUT REPEATING THE LANGUAGE.—It is possible to draft an amendment so that it directly addresses the problem set forth in paragraph (1) without repeating the language. For example, section 2661(m) of Public Law 98–369 provides:

> (m) Subparagraph (B) of section 223(c)(1) of such Act is amended by moving clause (iii) two ems to the left, and by moving the preceding provisions of such subparagraph two ems to the right, so that the left margin of such subparagraph and its clauses is indented four ems and is aligned with the margin of subparagraph (A) of such section.

For another example, see section 2663(a)(2)(A)(ii)(V) of Public Law 98–369. No standard approach has been devised.

SEC. 333. COMMITTEE AND FLOOR AMENDMENTS.

(a) GENERALLY FOLLOW RULES FOR AMENDMENTS TO STATUTES.—Except as noted in this section, the conventions and usages described in section 332 also apply in the case of any committee or House floor amendment. [12]

[12] An additional difference relates to the conventions discussed in section 332(c)(2). In committee and House floor amendments, it is the general practice of the House Legislative Counsel's office to use "by adding" only

LEGISLATIVE DRAFTING MANUAL

OFFICE OF THE LEGISLATIVE COUNSEL

UNITED STATES SENATE

FEBRUARY 1997

TABLE OF CONTENTS

(i) an American shorthair, a Burmese, a Manx, and a Siamese;

(ii) a collie, a dachshund, and a golden retriever;

(iii) a finch, a parrot, and a tweety bird; and

(iv) an iguana, a snake, and a turtle.

(C) EXCLUSIONS.—The term ''household pet'' does not include—

(i) a leopard;

(ii) a wolf;

(iii) a vulture; or

(iv) an alligator, a python, a Gila monster (unless the venom glands are removed), or a T Rex.

SEC. 126. AMENDMENTS TO STATUTES.

(a) METHOD.—

(1) IN GENERAL.—A provision is amended—

(A) by restating the provision, by striking the entire provision and reinserting it with changes or by amending the provision ''to read as follows:''; or

(B) by striking and inserting specific text.

(2) RESTATEMENT.—

(A) IN GENERAL.—In the restatement method, an Act or subdivision of an Act is changed without specific identification of what the changes are.

(B) FEATURES.—This method—

(i) aids understanding of the effect of the provision as amended;

(ii) provides an opportunity to improve the style of the unchanged portions;

(iii) requires a side-by-side comparison with the existing law to locate the specific changes made; and

(iv) results in the unchanged portions involved appearing in the bill, which is often tactically unacceptable and invites further amendment.

(3) STRIKE AND INSERT OF SPECIFIC TEXT.—

(A) IN GENERAL.—In the strike and insert method, the amendment is achieved by striking or inserting text. It is done, for example, by stating that X is ''amended by striking 'Y' and inserting 'Z' ''.

(B) FEATURES.—This method differs from an amendment by restatement in that the method—

(i) highlights the particular changes made (unless the number of changes is so great as to obscure each change);

(ii) avoids the risks caused by restating the unchanged text; and

(iii) requires a side-by-side comparison of the amendments and the existing law in

order to understand the effect of the amendments.

(C) ADDITION OF CLARIFYING TEXT.—Frequently a strike and insert amendment can be made more understandable by striking (and reinserting) more text than is technically necessary so as to provide context.

(b) SEQUENCE OF AMENDMENTS IN BILLS THAT AMEND STATUTES.—

(1) STRUCTURE OF AMENDED ACT.—Substantive amendments should appear in the numerical sequence of the sections of the Act amended or be organized by subject matter.

(2) CONFORMING AND TECHNICAL AMENDMENTS.—

(A) CONFORMING AMENDMENTS.—A conforming amendment is an amendment of a provision of law that is necessitated by the substantive amendments or provisions of the bill. The designation includes amendments, such as amendments to the table of contents, that formerly may have been designated as clerical amendments.

(B) TECHNICAL AMENDMENTS.—A technical amendment is a nonsubstantive amendment of a provision of law that may or may not

be related by subject matter to the substantive amendments or provisions of a bill, but is not necessitated by the amendments or provisions. In tax law, the designation often is used for amendments that have little or no revenue effect.

(C) LOCATION.—Conforming and technical amendments may be located immediately following the substantive amendments to which they relate (which tends to improve the organization and facilitate committee or floor amendments), or they may be located in a general conforming and technical amendments section and grouped and identified, by use of a heading, as relating to the substantive amendments.

(c) AMENDMENT TERMINOLOGY.—

(1) REFERENCE TO PROVISIONS TO BE AMENDED.—The forms are as follows:

(A) AMENDMENT IN A SINGLE SUBDIVISION.—

Section 123(a)(1) of the ABC Act (YY U.S.C. ZZZ(a)(1)) is amended . . .

(B) SAME AMENDMENT IN MORE THAN 1 SUBDIVISION.—

Clauses (i) and (ii) of section 123(a)(1)(A) of the ABC Act (YY U.S.C. ZZZ(a)(1)(A)) are each amended by . . . [*not* section 123(a)(1)(A) (i) and (ii)].

(2) REFERENCE TO MATTER TO BE STRICKEN.—

(A) DESCRIPTIVE CHARACTERIZATIONS.—Any characterization of text to be removed (such as ''the word'' or ''the phrase'') is surplusage. Example: Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended by striking ~~the phrase~~ ''by the Secretary''.

(B) METES AND BOUNDS REFERENCE FOR LENGTHY TEXT.—

(i) IDENTIFICATION OF BEGINNING AND END.—To strike a large block of text, strike the text by identifying the beginning and the end of the text.

(ii) FORMS.—The forms are as follows:

(I) STRIKE FROM 1 WORD OR PHRASE THROUGH ANOTHER.—

Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended by striking ''as determined by the Secretary'' and all that follows through ''opportunity for public comment''.

(II) STRIKE FROM A WORD OR PHRASE THROUGH THE PERIOD.—

Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended by striking ''as determined by the Secretary'' and all that follows and inserting a period.

(III) STRIKE OF MATTER PRECEDING A CUT-IN.—

Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended in the first sentence by striking the matter that precedes paragraph (1) and inserting the following: ''The Secretary shall not—''.

(C) ABOVE AND DOWN.—Do not use ''above'' or ''down''.

(D) STRIKE OUT.—Use ''strike'', not ''strike out''.

(E) IN LIEU THEREOF.—Use ''insert'', not ''insert in lieu thereof''.

(3) INSERTING OR ADDING.—In a bill amending a law, text is ''inserted'' within the text of a subdivision and ''added'' at the end of the subdivision.

(4) CUT-INS FOLLOWED BY FLUSH LANGUAGE.—

(A) USAGE.—It may be necessary when amending a provision with cut-in subdivisions to make clear that an addition to the end of the provision is not to be included in the last cut-in subdivision but is to appear after it.

(B) FORM.—The form is as follows:

Section 101(a) of the ABC Act (YY U.S.C. ZZZ(a)) is amended by adding after paragraph (4) the following flush sentence:

"The court may impose . . .".

(5) IMMEDIATELY.—Do not use "immediately" to identify where new text is to be placed. Example: Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended by inserting ~~immediately~~ after "good faith" the following: ", as determined by the Secretary,".

(6) THE FOLLOWING.—

(A) PROXIMITY TO COLON.—The term "the following" should be as close to the colon as possible.

(B) FORMS.—The forms are as follows:

(i) ADDITION AT END.—

Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended by adding at the end the following: [*not* by adding the following at the end:]

(ii) INSERTION.—

Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended by inserting after XXX the following: [*not* by inserting after XXX the following new paragraph:]

(7) THEREOF.—Do not use "thereof". "Thereof" as part of a description of the matter amended is surplusage. Example: Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended by adding at the end ~~thereof~~ the following:

(8) EACH PLACE RATHER THAN EACH TIME.—When amending a term that appears more than once in a subdivision, ''place'' rather than ''time'' should be used to refer to the locations of the term. Example: Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended by striking ''E, F, and G'' each ~~time~~ *place* it appears and inserting ''H, I, and J''.

(d) CUMULATIVE AMENDMENTS.—

(1) IN GENERAL.—If, after a first amendment to a provision is made in a draft, a series of sections or subdivisions is added sequentially to that provision, or if the provision is again amended, the assumption is that the earlier (preceding) amendments have been executed. However, to alert the reader to the fact that the provision is amended elsewhere in the draft, the following forms may be used:

(A) NEW PROVISION ADDED ELSEWHERE.—

Title XX of the ABC Act (YY U.S.C. ZZZ et seq.) is amended by adding after section *Y* (as added by *the last provision that makes an addition affecting the designation of the new section about to be added*) the following:

(B) OTHER AMENDMENT ELSEWHERE.—

Section 123 of the ABC Act (as amended by *the last provision that affects section 123 in such a way that the amendments to section 123 that follow make no sense if you look only at exist-*

ing law, e.g. subsections of section 123 have been redesignated) is amended . . . .

(2) USE OF U.S.C. CITES.—In a case such as that described in paragraph (1)(B), where the U.S.C. cite is uncertain, omit the U.S.C. cite.

(e) SERIES OF AMENDMENTS FOLLOWING A DASH.—For a series of amendments that is made to the same provision and that follows a dash, the form is as follows:

(a) IN GENERAL.—Section 123 of the ABC Act (YY U.S.C. ZZZ) is amended—

(1) in subsection (a), by striking ''not'';

(2) in the first sentence of subsection (b), by striking '', as determined by the Secretary,''; and

(3) by striking subsection (c).

(f) AMENDMENTS TO TABLES OF CONTENTS AND OTHER TABLES.—

(1) IN GENERAL.—The elements of a table of contents or any other table are referred to as ''items''.

(2) FORMS.—Items are amended as follows:

(A) WITHIN AN ITEM.—

The item relating to section 7 in the table of contents in section 1(b) of the ABC Act (YY U.S.C. prec. ZZZ) is amended by striking ''of Agriculture'' and inserting ''of Energy''.

(B) ENTIRE ITEM.—

The table of contents in section 1(b) of the ABC Act (YY U.S.C. prec. ZZZ) is amended by striking the item relating to section 7 and inserting the following:

''Sec. 7. Secretary of Energy.''.

(g) MARGIN AMENDMENTS.—

(1) IN GENERAL.—If existing law contains improper margin indentation or if an amendment being made affects indentation, clearly indicate an intent to change the indentation by using 1 of the following methods:

(A) INSTRUCTION TO INDENT APPROPRIATELY.—

Section 123(a) of the ABC Act (as redesignated by section X) is amended by redesignating subparagraph (A) as paragraph (1) and indenting appropriately.

(B) RESTATEMENT WITH APPROPRIATE INDENTATION.—

Section 123(a) of the ABC Act (as redesignated by section X) is amended by striking ''the Secretary'' and all that follows through ''(A) promulgate regulations'' and inserting the following: ''the Secretary of Housing and Urban Development shall—

''(1) promulgate regulations''.

(2) LAW A MESS WITH RESPECT TO INDENTATION.—If fixing the indentation in accordance with paragraph (1) would be too lengthy or confusing, amend the law by restatement.

information generated by monitoring, recordkeeping and reporting requirements described in this ICR is used by the Agency to ensure that facilities affected by the NSPS continue to operate the control equipment and achieve continuous compliance with the regulation. The collection of this information is mandatory. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15. The **Federal Register** document required under 5 CFR 1320.8(d), soliciting comments on this collection of information was published on October 29, 2001, (66 FR 54514). No comments were received.

Burden Statement: The annual public reporting and record keeping burden for this collection of information is estimated to average 238 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Respondents/Affected Entities: Owners and operators of municipal waste combustors.

Estimated Number of Respondents: 8.

Frequency of Response: One-time, quarterly, semi-annual and annual.

Estimated Total Annual Hour Burden: 11,885 hours.

Estimated Total Annualized Capital, O&M Cost Burden: $132,000.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the addresses listed above. Please refer to EPA ICR No. 1506.09 and OMB Control No. 2060–0210 in any correspondence.

Dated: January 31, 2002.

Oscar Morales,

Director, Collection Strategies Division.

[FR Doc. 02–3359 Filed 2–11–02; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[AD–FRL–7142–8]

RIN 2060–AI52

National Emission Standards for Hazardous Air Pollutants: Revision of Source Category List Under Section 112 of the Clean Air Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of revisions to the list of categories of major and area sources.

SUMMARY: This notice publishes revisions to the list of categories of major and area sources of hazardous air pollutants (HAP) emissions. The source category list, which is required under section 112(c) of the Clean Air Act (CAA), constitutes a significant part of EPA's agenda for regulating stationary sources of air toxics emissions. The list was most recently published in the **Federal Register** on January 30, 2001.

This notice meets the requirement in section 112(c)(1) to publish periodically, but at least once every 8 years, a list of all categories of sources reflecting revisions since the initial list was published. Several of the revisions identified in this notice have previously been published in actions associated with proposing and promulgating emission standards for individual source categories, and public comments have been requested in the context of those actions. Some of the revisions in this notice have not been reflected in any previous notices and are being made on the Administrator's own motion, without public comment. Such revisions are deemed by EPA to be without need for public comment based on the nature of the actions. This notice does not include any revisions to the schedule for standards provided for by CAA section 112(e).

EFFECTIVE DATE: February 12, 2002.

ADDRESSES: Docket No. A–90–49, containing supporting information used in development of this notice, is available for public inspection and copying between 8 a.m. and 5:30 p.m., Monday through Friday, excluding legal holidays. The docket is located in EPA's Air and Radiation Docket and Information Center, Waterside Mall, Room M–1500, 401 M Street, SW, Washington, DC 20460, or by calling (202) 260–7548. A reasonable fee may be charged for copying docket materials.

FOR FURTHER INFORMATION CONTACT: Ms. Maria Noell, U.S. EPA, Office of Air Quality Planning and Standards (OAQPS), Organic Chemicals Group (C504–4), Research Triangle Park, North Carolina 27711, telephone number (919) 541–5607, facsimile number (919) 541–3470, electronic mail address *noell.maria@epa.gov.*

SUPPLEMENTARY INFORMATION: *Docket.* The docket for this action is A–90–49. The docket is an organized file of all the information submitted to or otherwise relied upon by the Agency in the development of this revised list of source categories. The principal purpose of the docket is to allow interested parties to identify and locate documents that serve as a record of the process engaged in by the Agency to publish today's revision to the source category list. The docket is available for public inspection at EPA's Air and Radiation Docket and Information Center, which is listed in the **ADDRESSES** section of this notice.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of today's notice will also be available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the notice will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control. If more information regarding the TTN is needed, call the TTN HELP line at (919) 541–5384.

I. What Is the History of the Source Category List?

The CAA requires, under section 112, that EPA list all categories of major sources emitting HAP and such categories of area sources warranting regulation and promulgate national emission standards for hazardous air pollutants (NESHAP) to control, reduce, or otherwise limit the emissions of HAP from such categories of major and area sources. Pursuant to the various specific listing requirements in section 112(c), on July 16, 1992 (57 FR 31576), we published a list of 174 categories of major and area sources—referred to as the initial list—for which we would develop emission standards. On December 3, 1993 (58 FR 63941), pursuant to requirements in section 112(e), we published a schedule for the promulgation of emission standards for each of the 174 initially listed source categories.

When we publish notices that affect actions relating to individual source categories, it is important to reflect the resultant changes on the list and schedule. However, we published two separate notices where we listed sources for specific pollutants under section 112(c)(6) on April 10, 1998 (63 FR 17838), and additional area sources under section 112(k) on July 19, 1999 (64 FR 38706). Please refer to these specific notices for those listings. Since we have already listed those sources in previous **Federal Register** notices, we are not relisting them in this notice at this time. On June 4, 1996 (61 FR 28197), we published a notice that referenced all previous list and schedule changes and consolidated those actions, along with several new actions, into a revised source category list and schedule. Subsequently, we published four additional notices which updated the list and schedule: February 12, 1998 (63 FR 7155); May 17, 1999 (64 FR 26743); November 18, 1999 (64 FR 63025); and January 30, 2001 (66 FR 8220). You should read the previous notices for information relating to the development of the initial list and schedule and subsequent changes.

II. Why Is EPA Issuing This Notice?

This notice announces all list changes that have occurred since we last updated the list on January 30, 2001 (66 FR 8220). The changes and the affected source categories, are:

Changes to Source Category Names
- Friction Materials Manufacturing

Addition of Source Categories
- Coal- and Oil-Fired Electric Utility Steam Generating Units
- Wet-Formed Fiberglass Mat Production

Deletion of Source Categories
- Asphalt Concrete Manufacturing
- Uranium Hexafluoride
- Sewage Sludge Incineration

Subsumptions of Source Categories
- Cellulose Ethers Production
- Miscellaneous Viscose Processes

Changes to the Scope of a Source Category
- Process Heaters

The source category list and promulgation schedule, updated to include today's changes to the list as well as actions from previous notices, are presented in Table 1. Table 1 also includes **Federal Register** citations for notices related to the source categories (Table 1 omits proposal notices once a rule or rule amendment has been promulgated). Source categories for which revisions have been made in today's notice are annotated in Table 1 for ease in discerning where revisions have been made.

For general descriptions of source categories listed in Table 1, please refer to ''Documentation for Developing the Initial Source Category List'' (EPA–450/3–91–030) and the **Federal Register** notice for the first revision of the source category list and schedule (61 FR 28197, June 4, 1996). For subsequent changes to descriptions of source categories for which a rule has been promulgated, please consult Table 1 for the citation of the **Federal Register** notice that includes the amended definition and corresponding rule applicability.

III. What Are the Revisions EPA Is Making to the Source Category List?

The following sections describe revisions to the source category list since January 30, 2001.

A. Changes to Source Category Names

We are renaming the Friction Products Manufacturing source category to Friction Materials Manufacturing so that the name better describes the source category.

B. Addition of Source Categories

Section 112(n)(1)(A) of the CAA requires the Administrator to determine whether regulation of HAP from electric utility steam generating units is appropriate and necessary. This finding was to be made after the consideration of the results of the study mandated by the same section, reported to Congress in EPA's February 1998 ''Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress.'' The EPA gathered additional information and announced on December 20, 2000 (65 FR 79825) that regulation of HAP emissions from coal- and oil-fired electric utility steam generating units was appropriate and necessary. As a result of this determination, the source category for Coal- and Oil-Fired Electric Utility Steam Generating Units was added to the list of source categories under section 112(c) of the CAA in that December 20, 2000 notice. In today's notice, we are simply updating the source category list to reflect that addition.

Today's notice also updates the source category list to reflect the addition of a new source category called Wet-Formed Fiberglass Mat Production. For further information, you should refer to the proposed preamble for the NESHAP for Wet-Formed Fiberglass Mat Production (65 FR 34277), which serves as the official action for adding that source category.

C. Deletion of Source Categories

The Administrator may, where appropriate, delete categories of sources on the Administrator's own motion or on petition. In today's notice, we are deleting the Asphalt Concrete Manufacturing, Uranium Hexafluoride Production, and Sewage Sludge Incineration source categories on the Administrator's own motion. As discussed in the initial list notice (57 FR 31576), we included these categories on the list because at the time, we believed there were major sources in each category, either because they were major sources in their own right or because of collocation with other sources of HAP. These source categories are being deleted because available data indicate that there are no major sources in any of the source categories.

1. Asphalt Concrete Manufacturing

In today's notice, we are deleting the source category Asphalt Concrete Manufacturing because available data indicate that there are no major sources. This source category was initially listed in July 1992 because at the time, we believed there were major sources in the category. Emissions data, along with emission factors, were used to estimate HAP emissions from eleven asphalt concrete manufacturing plants employing various production processes and different fuels. Emissions of total HAP at individual plants range from 1.5 tons per year (tpy) to 6.4 tpy. In addition, emission factors were used to estimate HAP emissions from a plant with a high annual production of 1.2 million tons of asphalt concrete. We estimate total HAP emissions from that plant to be 6.2 tpy. Based on the above information, we have concluded that no asphalt concrete manufacturing facility has the potential to emit HAP approaching major source levels.

2. Uranium Hexafluoride Production

The Uranium Hexafluoride Production source category was initially listed in July 1992. Information collected since the listing indicates that there is only one facility producing uranium hexafluoride in the United States. We visited the facility and reviewed emissions estimates provided by the facility. We estimate total plantwide emissions of HAP, including emissions from uranium hexafluoride production and fluorine production, to be less than 5 tpy. Therefore, since there are no sources in this category with the potential to emit HAP at a level approaching the major source threshold, we are removing this source category from the list.

3. Sewage Sludge Incineration

The Sewage Sludge Incineration source category was initially listed in July 1992. Sewage sludge incinerators have been reevaluated for emissions of HAP. After evaluation of all emissions information available, including additional testing conducted since the initial listing, we have concluded that the Sewage Sludge Incineration source category does not have any sources with the potential to emit HAP at a level approaching major source levels; therefore, we are removing the Sewage Sludge Incineration source category from the list of source categories under CAA section 112.

D. Subsumptions of Source Categories

Today's notice updates the source category list to reflect the subsumption of seven categories related to cellulose production into two source categories called Cellulose Ethers Production and Miscellaneous Viscose Processes. We are combining the Carboxymethylcellulose Production, Cellulose Ethers Production, and Methylcellulose Production source categories into the Cellulose Ethers Production source category. We are also combining four existing source categories into a new source category called Miscellaneous Viscose Processes. This newly defined source category subsumes the Rayon Production, Cellulose Food Casing Manufacturing, Cellophane Production, and Cellulosic Sponge Manufacturing source categories. For further information, you should refer to the proposed preamble for the Cellulose Products Manufacturing NESHAP (65 FR 52166), which serves as the official action to combine the source categories and to name the newly defined source categories.

E. Changes to the Scope of a Source Category

Today's action serves to redefine the scope of the Process Heaters source category to only include indirect-fired process heaters.

Both direct-fired and indirect-fired process heaters were included in the initial listing of the source category. Direct-fired process heaters are those in which the products of combustion mix with process materials and the combined emissions exit the same stack. By contrast, indirect-fired process heaters are those where the process materials are not mixed with products of combustion and, therefore, the emissions arise solely from products of combustion. We included direct-fired process heaters under other MACT standards for each relevant industry source category since emissions from direct-fired heaters are source and industry specific and, therefore, only indirect-fired process heaters need to be included in the Process Heaters source category.

IV. Is This Action Subject to Judicial Review?

Section 112(e)(4) of the CAA states that, notwithstanding section 307 of the CAA, no action of the Administrator listing a source category or subcategory under section 112(c) shall be a final Agency action subject to judicial review, except that any such action may be reviewed under section 307 when the Administrator issues emission standards for such pollutant or category. Section 112(e)(3) states that the determination of priorities for promulgation of standards for the listed source categories is not a rulemaking and is not subject to judicial review, except that failure to promulgate any standard pursuant to the schedule established under section 112(e) shall be subject to review under section 304 of the CAA. Therefore, today's notice is not subject to judicial review.

V. Is EPA Asking for Public Comment?

Prior to issuance of the initial source category list, we published a draft initial list for public comment (56 FR 28548, June 21, 1991). Although we were not required to take public comment on the initial source category list, we believed it was useful to solicit input on a number of issues related to the list. Indeed, in most instances, even where there is no statutory requirement to take comment, we solicit public comments on actions we are contemplating. We have decided, however, that it is unnecessary to solicit additional public comment on the revisions reflected in today's notice. Where we believe it is useful to solicit input on certain actions, we will offer interested parties an opportunity to provide comments on proposed individual emission standards.

VI. Administrative Requirements

Today's notice is not a rule; it is essentially an information sharing activity which does not impose regulatory requirements or costs. Therefore, the requirements of Executive Order 13045 (Protection of Children from Environmental Health Risks and Safety Risks), Executive Order 13084 (Consultation and Coordination with Indian Tribal Governments), Executive Order 13132 (Federalism), the Regulatory Flexibility Act, the National Technology Transfer and Advancement Act, and the Unfunded Mandates Reform Act do not apply to today's notice. Also, this notice does not contain any information collection requirements and, therefore, is not subject to the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*

Under Executive Order 12866 (58 FR 51735, October 4, 1993), a regulatory action determined to be ''significant'' is subject to the Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Executive Order defines ''significant'' regulatory action as one that is likely to lead to a rule that may either (1) have an annual effect on the economy of $100 million or more, or adversely affect a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local or tribal governments or communities; (2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

The OMB has determined that this action is not significant under terms of Executive Order 12866.

Dated: February 6, 2002.

Robert Brenner,

Acting Assistant Administrator for Air and Radiation.

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Fuel Combustion:	
Coal- and Oil-fired Electric Utility Steam Generating Units	Added to 112(c) list 12/20/2000 (65FR79825)
Combustion Turbines	11/15/2000
Engine Test Facilities	11/15/2000
Industrial Boilers	11/15/2000
Institutional/Commercial Boilers	11/15/2000
Process Heaters	Redefined Scope as of Today 11/15/2000
Reciprocating Internal Combustion Engines	11/15/2000
Rocket Testing Facilities	11/15/2000
Stationary Internal Combustion Engines	Renamed 64FR63025(N)
Stationary Turbines	Renamed 64FR63025(N)
Non-Ferrous Metals Processing:	
Lead Acid Battery Manufacturing	Deleted 61FR28197(N)
Primary Aluminum Production	11/15/1997 62FR52383(F)
Primary Copper Smelting	11/15/2000 63FR19582(P) 63FR39326(SP)
Primary Lead Smelting	11/15/1997 64FR30194(F)
Primary Magnesium Refining	11/15/2000
Secondary Aluminum Production	11/15/1997 63FR55489(ap) 63FR55491(S) 65FR15689(F)
Secondary Lead Smelting	11/15/1994 60FR32587(F) 61FR27785(A) 61FR65334(A) 62FR32209(A) 63FR45007(A) 64FR4570(A) 64FR69637(A)
Ferrous Metals Processing:	
Coke By-Product Plants	Deleted 66FR8220(N)
Coke Ovens: Charging, Top Side, and Door Leaks	12/31/1992 58FR57898(F) 59FR01922(C)
Coke Ovens: Pushing, Quenching, and Battery Stacks	11/15/2000 66FR35326(P)
Ferroalloys Production	Renamed 64FR63025(N)
Ferroalloys Production: Silicomanganese and Ferromanganese	11/15/1997 64FR27450(F) 66FR16007(A) 66FR16024(a)
Integrated Iron and Steel Manufacturing	11/15/2000 66FR36836(P)
Iron Foundries	11/15/2000
Non-Stainless Steel Manufacturing—Electric Arc Furnace (EAF) Operation	Deleted 61FR28197(N)
Stainless Steel Manufacturing—Electric Arc Furnace (EAF) Operation	Deleted 61FR28197(N)
Steel Foundries	11/15/2000
Steel Pickling—HCl Process	Renamed 64FR63025(N)
Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants	11/15/1997 64FR33202(F)
Mineral Products Processing:	

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Alumina Processing	Deleted 66FR8220(N)
Asphalt Concrete Manufacturing	Deleted as of today
Asphalt Processing	11/15/2000
Asphalt Roofing Manufacturing	11/15/2000
Asphalt/Coal Tar Application—Metal Pipes	11/15/2000
Chromium Refractories Production	Renamed 64FR63025(N)
Clay Products Manufacturing	11/15/2000
Lime Manufacturing	11/15/2000
Mineral Wool Production	11/15/1997 64FR29490(F)
Portland Cement Manufacturing	11/15/1997 64FR31897(F)
Refractories Manufacturing	11/15/2000
Taconite Iron Ore Processing	11/15/2000
Wool Fiberglass Manufacturing	11/15/1997 64FR31695(F)
Petroleum and Natural Gas Production and Refining:	
Oil and Natural Gas Production	11/15/1997 64FR32610(F)
Natural Gas Transmission and Storage	11/15/2000 64FR32610(F)
Petroleum Refineries—Catalytic Cracking (Fluid and other) Units, Catalytic Reforming Units, and Sulfur Plant Units	Renamed 11/15/1997 66FR8220(N)
Petroleum Refineries—Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units	11/15/1997 63FR78890(P)
Petroleum Refineries—Other Sources Not Distinctly Listed	11/15/1994 60FR43244(F) 61FR07051(C) 61FR29876(C) 62FR07937(A)
Liquids Distribution:	
Gasoline Distribution (Stage 1)	11/15/1994 59FR42788(N) 59FR64303(F) 60FR07627(C) 60FR32912(C) 60FR43244(A) 60FR57628(C) 60FR62991(S) 61FR07718(A) 61FR58547(N) 62FR09087(A)
Marine Vessel Loading Operations	11/15/1997 60FR48399(F)
Organic Liquids Distribution (Non-Gasoline)	11/15/2000
Surface Coating Processes:	
Aerospace Industries	11/15/1994 60FR45956(F) 61FR04903(C) 61FR66227(C) 63FR15016(A) 63FR46525(A) 65FR3642(a)
Auto and Light Duty Truck (Surface Coating)	11/15/2000
Flat Wood Paneling (Surface Coating)	Renamed 64FR63025(N)
Large Appliance (Surface Coating)	Redefined Scope 11/15/2000 64FR63025(N) 65FR81134(P)
Magnetic Tapes (Surface Coating)	11/15/1994 59FR64580(F)
Manufacture of Paints, Coatings, and Adhesives	11/15/2000
Metal Can (Surface Coating)	11/15/2000

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Metal Coil (Surface Coating)	11/15/2000 63FR44616(P)
Metal Furniture (Surface Coating)	11/15/2000
Miscellaneous Metal Parts and Products (Surface Coating)	11/15/2000
Paper and Other Webs (Surface Coating)	11/15/2000 63FR55332(P)
Plastic Parts and Products (Surface Coating)	11/15/2000
Printing, Coating, and Dyeing of Fabrics	11/15/2000
Printing/Publishing (Surface Coating)	11/15/1994 61FR27132(F)
Shipbuilding and Ship Repair (Surface Coating)	11/15/1994 60FR64330(F) 61FR30814(A) 61FR66226(C)
Wood Building Products (Surface Coating)	11/15/2000
Wood Furniture (Surface Coating)	11/15/1994 60FR62930(F) 62FR30257(C) 62FR31361(A) 63FR71376(A)
Waste Treatment and Disposal:	
Hazardous Waste Incineration	11/15/2000 64FR52828(F)
Municipal Landfills	Renamed 11/15/2000 66FR8220(N)
Municipal Solid Waste Landfills	11/15/2000 63FR66672(P)
Off-Site Waste and Recovery Operations	11/15/1994 61FR34140(F) 64FR38950(A)
Publicly Owned Treatment Works (POTW) Renamed Emissions [c]	11/15/1995 66FR8220(N)
Publicly Owned Treatment Works (POTW) [c]	11/15/1995 64FR57572(F)
Sewage Sludge Incineration	Deleted as of today
Site Remediation	11/15/2000
Solid Waste Treatment, Storage and Disposal Facilities (TSDF)	Renamed 59FR51913(N)
Agricultural Chemicals Production:	
Pesticide Active Ingredient Production	11/15/1997 64FR33549(F)
4-Chloro-2-Methylphenoxyacetic Acid Production	Subsumed 64FR63025(N)
2,4-D Salts and Esters Production	Subsumed 64FR63025(N)
4,6-Dinitro-o-Cresol Production	Subsumed 64FR63025(N)
Butadiene-Furfural Cotrimer (R–11) Production [d]	Subsumed 64FR63025(N)
Captafol Production [d]	Subsumed 64FR63025(N)
Captan Production [d]	Subsumed 64FR63025(N)
Chloroneb Production	Subsumed 64FR63025(N)
Chlorothalonil Production [d]	Subsumed 64FR63025(N)
Dacthal (tm) Production [d]	Subsumed 64FR63025(N)
Sodium Pentachlorophenate Production	Subsumed 64FR63025(N)
Tordon (tm) Acid Production [d]	Subsumed 64FR63025(N)
Fibers Production Processes:	

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Acrylic Fibers/Modacrylic Fibers Production	11/15/1997 64FR34853(F) 64FR63695(A) 64FR63702(A) 64FR63779(a)
Spandex Production	11/15/2000 65FR76408(P)
Food and Agriculture Processes:	
Baker's Yeast Manufacturing	Renamed 64FR63025(N)
Manufacturing of Nutritional Yeast	11/15/2000 63FR55812(P) 66FR27876(F)
Solvent Extraction for Vegetable Oil Production	11/15/2000 63FR34251(P) 66FR19006(F)
Vegetable Oil Production	11/15/2000 66FR8220(N)
Pharmaceutical Production Processes:	
Pharmaceuticals Production [d]	11/15/1997 63FR19151(a) 63FR50280(F) 66FR40121(F) 66FR40903(P) 66FR40121(A) 66FR40166(P)
Polymers and Resins Production:	
Acetal Resins Production	11/15/1997 64FR34853(F) 64FR63695(A) 64FR63702(A) 64FR63779(a)
Acrylonitrile-Butadiene-Styrene Production	11/15/1994 61FR48208(F) 61FR54342(C) 61FR59849(N) 62FR01835(A) 62FR37720(A) 63FR9944(C) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Alkyd Resins Production	11/15/2000
Amino Resins Production	11/15/1997 65FR3275(F)
Boat Manufacturing	Redefined scope 11/15/2000 63FR43842(P) 64FR63025(N) 66FR44218(F)
Butyl Rubber Production	11/15/1994 61FR46906(F) 61FR59849(N) 62FR01835(A) 62FR12546(N) 62FR37720(A) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Cellulose Ethers Production	11/15/2000 65FR52166(P)
Carboxymethylcellulose Production	Subsumed as of today 11/15/2000
Methylcellulose Production	Subsumed as of today 11/15/2000
Epichlorohydrin Elastomers Production	11/15/1994 61FR46906(F) 61FR59849(N) 62FR01835(A) 62FR12546(N) 62FR37720(A) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Epoxy Resins Production	11/15/1994 60FR12670(F)
Ethylene-Propylene Rubber Production	11/15/1994 61FR46906(F) 61FR59849(N) 62FR01835(A) 62FR12546(N) 62FR37720(A) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Flexible Polyurethane Foam Production	11/15/1997 62FR05074(C) 64FR34853(F)
Hypalon (tm) Production [d]	11/15/1994 61FR46906(F) 61FR59849(N) 62FR01835(A) 62FR12546(N) 62FR37720(A) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Maleic Anhydride Copolymers Production	11/15/2000
Methyl Methacrylate-Acrylonitrile-Butadiene-Styrene Production [d]	11/15/1994 61FR48208(F) 61FR54342(C) 61FR59849(N) 62FR01835(A) 62FR37720(A) 63FR9944(C) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Methyl Methacrylate-Butadiene-Styrene Terpolymers Production [d]	11/15/1994 61FR48208(F) 61FR54342(C) 61FR59849(N) 62FR01835(A) 62FR37720(A) 63FR9944(C) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Neoprene Production	11/15/1994 61FR46906(F) 61FR59849(N) 62FR01835(A) 62FR12546(N) 62FR37720(A) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Nitrile Butadiene Rubber Production	11/15/1994 61FR46906(F) 61FR59849(N) 62FR01835(A) 62FR12546(N) 62FR37720(A) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Nitrile Resins Production	11/15/2000 61FR48208(F) 61FR54342(C) 61FR59849(N) 62FR01835(A) 62FR37720(A) 63FR9944(C) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Non-Nylon Polyamides Production	11/15/1994 60FR12670(F)
Nylon 6 Production	Deleted 63FR7155(N)
Phenolic Resins Production	65FR3275(F)

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Polybutadiene Rubber Production [d]	11/15/1994 61FR46906(F) 61FR59849(N) 62FR01835(A) 62FR12546(N) 62FR37720(A) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Polycarbonates Production [d]	11/15/1997 64FR34853(F) 64FR63695(A) 64FR63702(A) 64FR63779(a)
Polyester Resins Production	11/15/2000
Polyether Polyols Production	11/15/1997 64FR29420(F) 64FR31895(C)
Polyethylene Terephthalate Production	11/15/1994 61FR48208(F) 61FR54342(C) 61FR59849(N) 62FR01835(A) 62FR30993(A) 62FR37720(A) 63FR9944(C) 63FR15312(A) 63FR67879(N) 64FR11536(A) 64FR30406(A) 64FR30456(N) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Polymerized Vinylidene Chloride Production	11/15/2000
Polymethyl Methacrylate Resins Production	11/15/2000
Polystyrene Production	11/15/1994 61FR48208(F) 61FR54342(C) 61FR59849(N) 62FR01835(A) 62FR37720(A) 63FR9944(C) 63FR67879(N) 64FR11536(A) 64FR35023(S)
Polysulfide Rubber Production [d]	11/15/1994 61FR46906(F) 61FR59849(N) 62FR01835(A) 62FR12546(N) 62FR37720(A) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Polyvinyl Acetate Emulsions Production	11/15/2000
Polyvinyl Alcohol Production	11/15/2000

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Polyvinyl Butyral Production	11/15/2000
Polyvinyl Chloride and Copolymers Production	11/15/2000 65FR76958(P)
Reinforced Plastic Composites Production	11/15/2000 66FR40324(P)
Styrene-Acrylonitrile Production	11/15/1994 61FR48208(F) 61FR54342(C) 61FR59849(N) 62FR01835(A) 62FR37720(A) 63FR9944(C) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Styrene-Butadiene Rubber and Latex Production [d]	11/15/1994 61FR46906(F) 61FR59849(N) 62FR01835(A) 62FR12546(N) 62FR37720(A) 63FR67879(N) 64FR11536(A) 64FR35023(S) 66FR11233(A) 66FR11543(F) 66FR36924(A) 66FR40903(A)
Production of Inorganic Chemicals:	
Ammonium Sulfate Production—Caprolactam By-Product Plants	11/15/2000
Antimony Oxides Manufacturing	Promulgation rescheduled; deleted 64FR63025(N)
Carbon Black Production	11/15/2000 65FR76408(N)
Chlorine Production	11/15/2000
Chromium Chemicals Manufacturing	Deleted 61FR28197(N)
Cyanide Chemicals Manufacturing	11/15/2000 65FR76408(P)
Cyanuric Chloride Production	Deleted 63FR7155(N)
Fumed Silica Production	Corrected 11/15/2000 64FR63025(N)
Hydrochloric Acid Production	11/15/2000
Hydrogen Cyanide Production	Subsumed 63FR7155(N)
Hydrogen Fluoride Production	11/15/1997 64FR34853(F) 64FR63702(A) 64FR63779(a)
Phosphate Fertilizers Production	11/15/1997 64FR31358(F)
Phosphoric Acid Manufacturing	11/15/1997 64FR31358(F)
Quaternary Ammonium Compounds Production	Moved 61FR28197(N)
Sodium Cyanide Production	Subsumed 63FR7155(N)
Uranium Hexafluoride Production	Deleted as of today
Production of Organic Chemicals:	

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Ethylene Processes	11/15/2000 65FR76408(P)
Quaternary Ammonium Compounds Production	11/15/2000
Synthetic Organic Chemical Manufacturing	11/15/1992 59FR19402(F) 59FR29196(A) 59FR32339(N) 59FR48175(C) 59FR53359(S) 59FR54131(S) 60FR05320(A) 60FR18020(A) 60FR18026(A) 60FR63624(C) 61FR31435(A) 61FR07716(A) 61FR43544(N) 61FR64572(A) 62FR02722(A) 63FR67787(A) 64FR20189(C) 65FR3169(a)
Tetrahydrobenzaldehyde Production	Subsumed 63FR26078(F) 64FR63025(N)
Miscellaneous Processes:	
Aerosol Can-Filling Facilities	Promulgation rescheduled; deleted 64FR63025(N)
Benzyltrimethylammonium Chloride Production	11/15/2000
Butadiene Dimers Production	Renamed 61FR28197
Carbonyl Sulfide Production	11/15/2000
Chelating Agents Production	11/15/2000
Chlorinated Paraffins Production [d]	11/15/2000
Chromic Acid Anodizing	11/15/1994 60FR04948(F) 60FR27598(C) 60FR33122(C) 61FR27785(A) 61FR04463(A) 62FR42918(A)
Commercial Dry Cleaning (Perchloroethylene) —Transfer Machines	11/15/1992 58FR49354(F) 58FR66287(A) 60FR64002(A) 61FR27785(A) 61FR49263(A)
Commercial Sterilization Facilities	11/15/1994 59FR62585(F) 61FR27785(A) 64FR67789(A) 64FR69637(A)
Decorative Chromium Electroplating	11/15/1994 60FR04948(F) 60FR27598(C) 60FR33122(C) 61FR27785(A) 61FR04463(A) 62FR42918(A) 64FR69637(A)
Dodecanedioic Acid Production	Subsumed 59FR19402(N)
Dry Cleaning (Petroleum Solvent)	Deleted 66FR8220(N)
Ethylidene Norbornene Production [d]	11/15/2000

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Explosives Production	11/15/2000
Flexible Polyurethane Foam Fabrication Operations	11/15/2000 66FR41718(P)
Friction Materials Manufacturing	Name Changed as of Today 11/15/2000
Halogenated Solvent Cleaners	11/15/1994 59FR61801(F) 59FR67750(C) 60FR29484(C) 63FR24749(S) 63FR68397(A) 64FR45187(A) 64FR56173(A) 64FR67793(A) 64FR69637(A) 64FR67793(A)
Hard Chromium Electroplating	11/15/1994 60FR04948(F) 60FR27598(C) 60FR33122(C) 61FR27785(A) 61FR04463(A) 62FR42918(A) 64FR69637(A)
Hydrazine Production	11/15/2000
Industrial Cleaning (Perchloroethylene)—Dry-to-dry machines	11/15/1992 58FR49354(F) 58FR66287(A) 60FR64002(A) 61FR27785(A) 61FR49263(A)
Industrial Dry Cleaning (Perchloroethylene)—Transfer Machines	11/15/1992 58FR49354(F) 58FR66287(A) 60FR64002(A) 61FR27785(A) 61FR49263(A)
Industrial Process Cooling Towers	11/15/1994 59FR46339(F)
Leather Finishing Operations	11/15/2000 63FR58702(P)
Leather Tanning and Finishing Operations	Renamed 66FR8220(N)
Miscellaneous Viscose Processes	Added as of today 11/15/2000 65FR52166(P)
Cellophane Production	Subsumed as of today 11/15/2000 65FR52166(P)
Cellulose Food Casing Manufacturing	Subsumed as of today 11/15/2000 65FR52166(P)
Cellulosic Sponge Manufacturing	Subsumed as of today Added 11/15/2000 64FR63025 65FR52166(P)
Rayon Production	Subsumed as of today 11/15/2000 65FR52166(P)
OBPA/1,3-Diisocyanate Production [d]	11/15/2000
Paint Stripper Users	Renamed 64FR63025(N)
Paint Stripping Operations	11/15/2000
Photographic Chemicals Production	11/15/2000

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Phthalate Plasticizers Production	11/15/2000
Plywood and Composite Wood Products	11/15/2000
Plywood/Particle Board Manufacturing	Renamed 64FR63025(N)
Polyether Polyols Production	Moved 61FR28197(N)
Pulp and Paper Production	Promulgation rescheduled 11/15/2000 64FR63025 63FR18504(F) 63FR42238(C) 63FR49455(A) 63FR71385(A) 64FR17555(A) 65FR3907(a) 65FR80755(F) 66FR24268(C)
Rocket Engine Test Firing	Moved and renamed 64FR63025(N)
Rubber Chemicals Manufacturing	11/15/2000
Rubber Tire Manufacturing	11/15/2000 63FR62414(P)
Semiconductor Manufacturing	11/15/2000
Symmetrical Tetrachloropyridine Production [d]	11/15/2000
Tetrahydrobenzaldehyde Production	Moved 64FR63025(N)
Tire Production	Renamed 64FR63025(N)
Wet-Formed Fiberglass Mat Production	Added as of today 11/15/2000 65FR34277(P)
Wood Treatment	Deleted 61FR28197(N)
Categories of Area Sources:	
Asbestos Processing	Deleted 60FR61550
Chromic Acid Anodizing	11/15/1994 60FR04948(F) 60FR27598(C) 60FR33122(C) 61FR27785(A) 61FR04463(A) 62FR42918(A) 64FR69637(A)
Commercial Dry Cleaning (Perchloroethylene) -Dry-to-Dry Machines	11/15/1992 58FR49354(F) 58FR66287(A) 60FR64002(A) 61FR27785(A) 61FR49263(A) 64FR69637(A)
Commercial Dry Cleaning (Perchloroethylene) -Transfer Machines	11/15/1992 58FR49354(F) 58FR66287(A) 60FR64002(A) 61FR27785(A) 61FR49263(A) 64FR69637(A)
Commercial Sterilization Facilities	11/15/1994 59FR62585(F) 61FR27785(A) 64FR67789(A) 64FR69637(A)

TABLE 1.—CATEGORIES OF SOURCES OF HAZARDOUS AIR POLLUTANTS AND REGULATION PROMULGATION SCHEDULE BY INDUSTRY GROUP—Continued

[Revision date: February 12, 2002]

Industry group Source category [a]	Statutory promulgation date/**Federal Register** citation [b]
Decorative Chromium Electroplating	11/15/1994 60FR04948(F) 60FR27598(C) 60FR33122(C) 61FR27785(A) 61FR04463(A) 62FR42918(A) 64FR69637(A)
Halogenated Solvent Cleaners	11/15/1994 59FR61801(F) 59FR67750(C) 60FR29484(C) 63FR24749(S) 63FR68397(A) 64FR45187(A) 64FR56173(A) 64FR67793(A) 64FR69637(A) 64FR67793(A)
Hard Chromium Electroplating	11/15/1994 60FR04948(F) 60FR27598(C) 60FR33122(C) 61FR27785(A) 61FR04463(A) 62FR42918(A) 64FR69637(A)
Hazardous Waste Incineration	11/15/2000 64FR52828(F)
Portland Cement Production	11/15/1997 64FR31897(F)
Secondary Aluminum Production	11/15/1997 63FR55489(ap) 63FR55491(S) 65FR15689(F)
Secondary Lead Smelting	11/15/1997 60FR32587(F) 61FR27785(A) 61FR65334(A) 62FR32209(A) 64FR69637(A)

[a] Only sources within any category located at a major source shall be subject to emission standards under CAA section 112 unless a finding is made of a threat of adverse effects to human health or the environment for the area sources in a category. All listed categories are exclusive of any specific operations or processes included under other categories that are listed separately.

[b] This schedule does not establish the order in which the rules for particular source categories will be proposed or promulgated. Rather, it requires that emissions standards pursuant to CAA section 112(d) for a given source category be promulgated by the specified date.

The markings in the ''Statutory Promulgation Date/**Federal Register** Citation'' column of Table 1 denote the following:

(A): final amendment to a final rulemaking action
(a): proposed amendment to a final rulemaking action
(C): correction (or clarification) published subsequent to a proposed or final rulemaking action
(F): final rulemaking action
(N): notice to announce general information, such as an Agency decision, availability of new data, administrative updates, etc.
(P): proposed rulemaking action
(ap): advance notice of proposed rulemaking action
(R): reopening of a proposed action for public comment
(S): announcement of a stay, or partial stay, of the rule requirements
Moved: the source category is relocated to a more appropriate industry group
Subsumed: the source category is included within the definition of another listed category and therefore is no longer listed as a separate source category
Renamed: the title of this source category is changed to a more appropriate title
Deleted: the source category is removed from the source category list

[c] The Publicly Owned Treatment Works (POTW) Emissions source category had a statutory deadline for regulatory promulgation of November 15, 1995, as established by CAA section 112(e)(5). However, for purposes of determining the 18-month period applicable to the POTW source category under section 112(j)(2), the promulgation deadline was November 15, 1997. This latter date is consistent with the section 112(e) schedule for the promulgation of emissions standards, as published in the **Federal Register** on December 3, 1993 (58 FR 63941).

[d] Equipment handling specific chemicals for these categories or subsets of these categories is subject to a negotiated standard for equipment leaks contained in the Hazardous Organic NESHAP (HON), which was promulgated on April 22, 1994. The HON includes a negotiated standard for equipment leaks from the SOCMI category and 20 non-SOCMI categories (or subsets of these categories). The specific processes affected within the categories are listed in Section XX.XO(c) of the March 6, 1991 **Federal Register** notice (56 FR 9315).

[FR Doc. 02–3348 Filed 2–11–02; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7141–5]

Notice of Open Meeting; Environmental Financial Advisory Board; March 4–6, 2002

The Environmental Protection Agency's (EPA) Environmental Financial Advisory Board (EFAB) will hold two open meetings on March 4–6, 2002. Both meetings will be held at the National Press Club, 14th and F Streets, NW., Washington, DC, 13th Floor.

On Monday, March 4, 2002 EFAB's Cost Effective Environmental Management Workgroup (CEM) will hold a Workshop on the Governmental Accounting Standards Board Statement No. 34 (GASB 34). The meeting will be held in the Zenger Room and will begin at 9 a.m. and end at approximately 3 p.m.

The purposes of the workshop are to: (1) Gain a better understanding of GASB 34 among EFAB members and EPA staff; (2) assess how various stakeholders might be affected by implementation of the standard and examine its implications; and (3) identify possible recommendations for EFAB to make to EPA with respect to its role and any action it may take. The meeting will consist of a group of informed panelists from the Government Accounting Standards Board, public utilities, EPA, as well as the financial services industry, who will share their perspectives on GASB 34. Information from this meeting will help the Board develop a report with advice and recommendations to EPA.

On March 5–6, 2002 a meeting of the full Board will be held in the Holeman Lounge. The Tuesday, March 5 session will run from 8:30 a.m. to 5 p.m. and the Wednesday, March 6 session will begin at 8 a.m. and end at 11 a.m.

The purposes of this meeting are to: (1) Hear from informed speakers on environmental finance issues, proposed legislation and Agency priorities; and (2) discuss progress with work products under EFAB's current strategic action agenda. Environmental financing topics expected to be discussed include: Stewardship financing, cost-effective environmental management, international initiatives, superfund and brownfields initiatives, and public finance issues.

Both meetings are open to the public, but seating is limited. For further information, please contact Vanessa Bowie, EFAB Coordinator, U.S. EPA on (202) 564–5186.

Dated: February 4, 2002.

Joseph Dillon,

Comptroller.

[FR Doc. 02–3358 Filed 2–11–02; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7142–1]

Paying for Water Quality: Managing Funding Programs To Achieve the Greatest Environmental Benefits; a Public Workshop

AGENCY: Environmental Protection Agency.

ACTION: Notice of public meeting.

SUMMARY: The Environmental Protection Agency will hold a public workshop on March 14–15, 2002, to provide a forum to discuss how water quality funding programs can be managed and enhanced to achieve the greatest environmental benefit.

DATES: The workshop will be held on March 14–15, 2002.

ADDRESSES: The workshop will be held at the Environmental Protection Agency, EPA East Building, 1201 Constitution Avenue, NW., Washington, DC 20004, in the EPA Hearing Room, Room 1153.

FOR FURTHER INFORMATION CONTACT: Jordan Dorfman, Environmental Protection Agency, Office of Wastewater Management, State Revolving Fund Branch; telephone: 202–564–0614; e-mail: *dorfman.jordan@epa.gov*

Registration: Though the workshop is free, registration is requested for planning purposes. Please send your name, title, affiliation, address, phone number, fax, and email to Nikki Cleaveland at Northbridge Environmental, by fax, 202–625–0461, or by email, *ncleaveland@nbenvironmental.com.*

SUPPLEMENTARY INFORMATION: EPA will convene this public workshop, Paying for Water Quality: Managing Funding Programs to Achieve the Greatest Environmental Benefits, to discuss the current status of water quality funding in the United States, provide an overview of funding programs and illustrate their use through case studies by practitioners from around the country. The Committee on Appropriations, in House Report 107–159, identified a range of issues affecting water quality. The Committee particularly focused on issues concerning nonpoint source pollution. It noted that ''septic system repair and management projects and other nonpoint source pollution prevention and control measures, which can produce substantial benefits of water quality protection, are not eligible for SRF funding in most of the states.'' It also noted that many recipients of federal funding have not instituted user fees to provide for long-term maintenance of infrastructure.

To address these problems, EPA will hold a workshop to provide a forum to discuss how water quality funding programs can be managed and enhanced to achieve the greatest environmental benefit. The agenda will include topics such as an overview of the Clean Water State Revolving Fund program, the role of other federal water quality funding programs, funding decentralized wastewater systems and nonpoint source projects, exploring the use of environmental outcomes and affordability studies, environmental performance tracking, and efficient wastewater management. Invited to the workshop will be representatives from the State/EPA SRF Workgroup, the Environmental Council of the States, Environmental Finance Centers, centralized and decentralized wastewater and nonpoint source stakeholder groups and any member of the public who wishes to attend. Participants will have the opportunity to openly discuss present concerns and possible solutions.

Dated: February 6, 2002.

Richard T. Kuhlman,

Director, Municipal Support Division, Office of Wastewater Management.

[FR Doc. 02–3364 Filed 2–11–02; 8:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7142–7]

Operating Industries, Inc. Landfill Superfund Site; Notice of Proposed CERCLA Administrative De Minimis Settlement

AGENCY: Environmental Protection Agency.

ACTION: Notice; request for public comment.

SUMMARY: In accordance with section 122(i) of the Comprehensive Environmental Response, Compensation, and Liability Act, as amended (''CERCLA''), 42 U.S.C. 9622(i), the Environmental Protection Agency (''EPA'') is hereby providing notice of a proposed administrative *de*

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[OAR–2002–0056; FRL–7887–7]

RIN 2060–AM96

Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is revising the regulatory finding that it issued in December 2000 pursuant to section 112(n)(1)(A) of the Clean Air Act (CAA), and based on that revision, removing coal- and oil-fired electric utility steam generating units (''coal- and oil-fired Utility Units'') from the CAA section 112(c) source category list. Section 112(n)(1)(A) of the CAA is the threshold statutory provision underlying today's action. That provision requires EPA to conduct a study to examine the hazards to public health that are reasonably anticipated to occur as the result of hazardous air pollutant (HAP) emissions from Utility Units after imposition of the requirements of the CAA. The provision also provides that EPA shall regulate Utility Units under section 112, but only if the Administrator determines that such regulation is both ''appropriate'' and ''necessary'' considering, among other things, the results of the study. EPA completed the study in 1998 (the Utility Study), and in December 2000 found that it was ''appropriate and necessary'' to regulate coal- and oil-fired Utility Units under CAA section 112. That December 2000 finding focused primarily on mercury (Hg) emissions from coal-fired Utility Units. In light of the finding, EPA in December 2000 announced its decision to list coal- and oil-fired Utility Units on the section 112(c) list of regulated source categories. In January 2004, EPA proposed revising the December 2000 appropriate and necessary finding and, based on that revision, removing coal- and oil-fired Utility Units from the section 112(c) list.

By this action, we are revising the December 2000 appropriate and necessary finding and concluding that it is neither appropriate nor necessary to regulate coal- and oil-fired Utility Units under section 112. We are taking this action because we now believe that the December 2000 finding lacked foundation and because recent information demonstrates that it is not appropriate or necessary to regulate coal- and oil-fired Utility Units under section 112. Based solely on the revised finding, we are removing coal- and oil-fired Utility Units from the section 112(c) list. The reasons supporting this action are described in detail below. Other actions related to this final rule include the recent promulgation of the final Clean Air Interstate Rule (CAIR) and the final Clean Air Mercury Rule (CAMR).

DATES: *Effective Date:* The effective date of the final rule is March 29, 2005.

ADDRESSES: EPA has established a docket for this action under Docket ID No. OAR–2002–0056. All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket.* Although listed in the index, some information is not publicly available, *i.e.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the EPA Docket Center (EPA/DC), EPA West Building, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Wendy Blake, OGC Attorney, Office of General Counsel, Environmental Protection Agency, (AR–2344), Washington, DC 20460 telephone number: (202) 564–1821; fax number: (202) 564–5603; e-mail address: *blake.wendy@epa.gov.*

Judicial Review. Pursuant to CAA section 307(b), judicial review of this final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by May 31, 2005. EPA designates this action a CAA section 307(d) rulemaking. (See CAA section 307(d)(1)(V); 69 FR 4653 (January 30, 2004).) Under CAA section 307(d)(7)(B), only an objection to the rule that was raised with reasonable specificity during the time period for public comment can be raised during judicial review. Section 307(d)(7)(B) further provides that if the person raising the objection can demonstrate to the Administrator that it was impracticable to raise the objection during the public comment period or if the grounds for the objection arose after the public comment period but within the time period specified for judicial review and if the objection is of central relevance, EPA will convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed.

I. Statutory Background

In the 1990 Amendments to the CAA, Congress substantially modified CAA section 112, the provision of the CAA addressing HAP. Among other things, section 112 contains a list of ''hazardous air pollutants,'' which are ''pollutants which present, or may present, * * * a threat of adverse human health effects * * * or adverse environmental effects whether through ambient concentrations, bioaccumulation, deposition, or otherwise.'' (See CAA section 112(b)(2).) In the 1990 amendments to the CAA, Congress listed 190 HAP, and authorized EPA to add or remove pollutants from the list.[1] (See CAA Section 112(b)(1)–(b)(3).)

The types of sources addressed under section 112 include: major sources, area sources, and electric utility steam generating units (Utility Units). (See CAA 112(a)(1), (a)(2), (a)(8).) A ''major source'' is any stationary source[2] or group of stationary sources at a single location and under common control that emits or has the potential to emit ten tons or more per year of any HAP or 25 tons or more per year of any combination of HAP. (See CAA 112(a)(1).) A stationary source of HAP that is not a ''major source'' is an ''area source.'' (See CAA 112(a)(2).) Finally, an electric utility steam generating unit is any ''fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.'' (See CAA 112(a)(8).)

There are two important steps under section 112: (1) Determining whether a source category meets the statutory criteria for regulation under section 112; and (2) promulgating emission standards for those source categories regulated under section 112. In terms of the first step, Congress required EPA to publish a list of categories and

[1] The current section 112(b) list includes 188 HAP.

[2] A ''stationary source'' of hazardous air pollutants is any building, structure, facility or installation that emits or may emit any air pollutant. (See CAA Section 111(a)(3) and 112(a)(3).)

subcategories of major sources and area sources by November 15, 1991.[3] (See CAA 112(c)(1) & (c)(3).) Congress further directed EPA to revise this initial list periodically, based on, for example, new information. (See 112(c)(1).) EPA is required to list a category of major sources under section 112(c)(1) if at least one stationary source in the category meets the definition of a major source—*i.e.*, if a certain amount of a HAP (or combination of HAP) is emitted from the source. (See 112(a)(1).) By contrast, EPA is required to list categories or subcategories of area sources only if they meet one of the following statutory criteria: (1) EPA determines that the category of area sources presents a threat of adverse effects to human health or the environment that warrants regulation under CAA section 112; or (2) the category of area sources falls within the purview of CAA section 112(k)(3)(B) (the Urban Area Source Strategy). (See CAA 112(c)(3).)

For those source categories regulated under section 112, the next step concerns the establishment of emission standards. Under section 112(d), EPA must establish emission standards that ''require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section'' that the Administrator determines is achievable based on technology, taking into account certain factors such as cost, energy requirements, and other impacts. The emission standard for new sources cannot be, however, less stringent than the level of control achieved by the best controlled similar source, and the emission standard for existing sources cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources in the category, regardless of cost, energy requirements and other impacts. CAA 112(d)(2) and (3). Finally, within eight years after promulgation of section 112(d) emission standards for a listed source category, EPA must promulgate additional standards if such standards are necessary to provide an ample margin of safety to protect public health or to prevent an adverse environmental effect. (See CAA section 112(f).) These additional standards under CAA section 112(f) are commonly referred to as ''residual risk'' standards.

The criteria for listing major and area sources established in section 112(c)(1) and (c)(3) do not apply to Utility Units because Congress treated Utility Units differently from other major and area sources. Indeed, Congress enacted a special provision for Utility Units in section 112(n)(1)(A), which governs whether Utility Units should even be regulated under section 112.[4] Section 112(n)(1)(A) directs EPA to conduct a study to evaluate what ''hazards to public health [are] reasonably anticipated to occur'' as the result of HAP emissions from Utility Units ''after imposition of the requirements of th[e] Act,'' (emphasis added) and to report the results of such study to Congress by November 15, 1993. Congress also directed EPA to describe in the report to Congress ''alternative control strategies for [those] emissions that may warrant regulation under this section.'' (See CAA section 112(n)(1)(A).) Section 112(n)(1)(A) further provides that EPA shall regulate Utility Units under section 112 if the Administrator determines, considering the results of the study, that such regulation is ''appropriate and necessary.'' Thus, unlike other major and area sources, Congress first required EPA to examine how ''imposition of the requirements of th[e] Act'' would affect the overall level of utility HAP emissions, and then determine whether regulation of Utility Units under section 112 is both appropriate and necessary. Section 112(n)(1)(A) therefore sets an important and unique condition precedent for regulating Utility Units under section 112 and provides EPA discretion in determining whether that condition precedent has been met.

II. Regulatory Background

A. EPA's December 20, 2000 Regulatory Finding

On December 20, 2000, EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired Utility Units under section 112. In making that finding, EPA considered the Utility Study, which was completed and submitted to Congress in February 1998.

In the Utility Study, we divided Utility Units into three subcategories based on fuel type: coal-, oil-, and gas-fired units. We then analyzed HAP emissions from each subcategory. We followed this approach because each subcategory burns a different fuel, which, in turn, leads to different emissions profiles, which can require different emission controls. This approach is also consistent with EPA's historical practice of subcategorizing Utility Units based on fuel type. (*See, e.g.,* 40 CFR 60.44(a).)

Because EPA subcategorized Utility Units for purposes of the Utility Study, EPA, in December 2000, made separate ''appropriate and necessary'' findings under section 112(n)(1)(A) for gas-fired, coal-fired, and oil-fired Utility Units. In making these findings, EPA considered the Utility Study and certain additional information obtained after completion of the Utility Study, including the National Academy of Sciences' report concerning the health effects of methylmercury and actual emissions data obtained in response to an information collection request EPA issued to all coal-fired Utility Units in 1999. *See* 65 FR 79826. EPA reasonably relied on this additional information because the information provided a more comprehensive and contemporaneous record concerning Hg emissions from coal-fired units. Nothing in section 112(n)(1)(A) suggests that Congress sought to preclude EPA from considering more current information in making the appropriate and necessary finding.

In the December 2000 finding, EPA determined that it was appropriate and necessary to regulate coal- and oil-fired units, but not gas-fired units.[5] With respect to the latter, EPA found that regulation of HAP emissions from natural gas-fired Utility Units ''is not appropriate or necessary because the *impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC.*'' (Emphasis added) *See* 65 FR 79831.

EPA provided three primary reasons in support of its finding that it was ''appropriate'' to regulate coal- and oil-fired Utility Units under section 112. First, EPA found that it was appropriate to regulate HAP emissions from coal- and oil-fired Utility Units because Utility Units ''are the largest domestic source of Hg emissions.'' *See* 65 FR 79830. EPA next found that it was

[3] EPA published the initial list on July 16, 1992. See 57 FR 31,576, July 16, 1992. EPA did not include Utility Units on the initial section 112(c) list because Congress required EPA to conduct and consider the results of the study required by section 112(n)(1)(A) before regulating these units and, therefore, listing in 1992 was not authorized by statute.

[4] No one would dispute that certain Utility Units would meet the definition of a ''major source'' based on the quantity of HAP emitted from such units, or that other Utility Units may meet the ''area source'' criteria for listing under section 112(c)(3), but Congress recognized this fact in 1990 and specifically enacted section 112(n)(1)(A), which establishes an entirely different test for determining whether Utility Units should be regulated under section 112.

[5] Although the December 2000 finding addressed three subcategories of Utility Units—coal-, oil-, and gas-fired units, the majority of the finding concerned Hg emissions from coal-fired power plants. 65 FR 79826–29 (explaining that Hg from coal-fired units is the HAP of greatest concern); Utility Study, ES–27 (''mercury from coal-fired utilities is the HAP of greatest potential concern.'').

appropriate to regulate coal- and oil-fired Utility Units because ''mercury in the environment presents significant hazards to public health and the environment.''[6] *See* 65 FR 79830. Finally, EPA explained that it was appropriate to regulate HAP emissions from coal- and oil-fired units because it had identified certain control options that, it anticipated, would effectively reduce HAP from such units. In discussing the appropriate finding, EPA also noted that uncertainties remained concerning the extent of the public health impact from HAP emissions from oil-fired units. Thus, EPA's determination that it was ''appropriate'' to regulate coal- and oil-fired units under section 112 hinged on the health effects associated with Hg emissions from coal-fired Utility Units, the uncertainties associated with the health effects of HAP from oil-fired Utility Units, and EPA's belief that control options would be available to reduce certain utility HAP emissions.[7]

Once EPA determined that it was ''appropriate'' to regulate coal- and oil-fired Utility Units under section 112 of the CAA, EPA next concluded that it was also ''necessary'' to regulate HAP emissions from such units under section 112. Interpreting the term ''necessary'' in section 112(n)(1)(A), EPA found that it was necessary to regulate HAP from coal- and oil-fired Utility Units ''because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions identified in the Utility RTC.'' *See* 65 FR 79830.

In light of the positive appropriate and necessary determination, EPA in December 2000 listed coal- and oil-fired Utility Units on the section 112(c) source category list. *See* 65 FR 79831 (our finding that it is appropriate and necessary to regulate coal- and oil-fired Utility Units under section 112 ''adds these units to the list of source categories under section 112(c).''). Relying on CAA section 112(e)(4), EPA explained in its December 2000 finding that neither the appropriate and necessary finding under section 112(n)(1)(A), nor the associated listing were subject to judicial review at that time. EPA did not add natural-gas fired units to the section 112(c) list in December 2000 because it did not make a positive appropriate and necessary finding for such units.

B. Litigation Challenging December 2000 Regulatory Finding

Shortly after issuance of the December 2000 Finding, an industry group challenged the December 2000 finding in the United States Court of Appeals for the District of Columbia Circuit (DC Circuit). *UARG* v. *EPA,* 2001 WL 936363, No. 01–1074 (DC Cir. July 26, 2001). EPA moved to dismiss the lawsuit on the basis of section 112(e)(4), which provides, in pertinent part, that ''no action of the Administrator * * * listing a source category or subcategory under subsection (c) of this section *shall be a final agency action subject to judicial review,* except that any such action may be reviewed under such section 7607 of this title when the Administrator issues emission standards for such pollutant or category.'' (Emphasis added.) (*See* CAA Section 112(e)(4).)

In its motion to dismiss the petition, EPA argued to the DC Circuit, among other things, that the December 2000 listing of coal- and oil-fired Utility Units was inseparable from the appropriate and necessary finding and that the appropriate and necessary finding and listing actions are not final agency actions pursuant to section 112(e)(4). *See also* 65 FR 79826. EPA further noted in its motion to dismiss that both the finding and the listing would be subject to additional notice and comment as part of the section 112(d) rulemaking. *See* EPA's Motion to Dismiss, *UARG* v. *EPA*, 2001 WL 936363, No. 01–1074S (''Because the decision to add coal and oil fired electric utility steam generating units to the source category list is not yet final agency action, it will be among the matters subject to further comment in the subsequent [standards] rulemaking.''); 65 FR 79831 (noting that issues related to the listing, such as ''the exact dimension of the source category,'' will be subject to additional comment in the emission standard rulemaking process). The DC Circuit dismissed the challenge to the December 2000 finding for lack of jurisdiction based on section 112(e)(4) of the CAA. The December 2000 finding and associated listing are therefore not final agency actions.

C. January 30, 2004 Proposed Rule and March 2004 Supplemental Notice

On January 30, 2004, EPA published in the **Federal Register** a proposed rule entitled ''Proposed National Emissions Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units.'' (*See* 69 FR 4652 (January 30, 2004).) In that rule, EPA proposed three alternative regulatory approaches. First, EPA proposed to retain the December 2000 Finding and associated listing of coal- and oil-fired Utility Units and to issue under section 112(d) maximum achievable control technology-based (MACT) emission standards for both subcategories. Second, EPA alternatively proposed revising the Agency's December 2000 Finding, removing coal and oil-fired Utility Units from the section 112(c) list,[8] and issuing final standards of performance under CAA section 111 for new and existing coal-fired units that emit Hg and new and existing oil-fired units that emit nickel. Finally, as a third alternative, EPA proposed retaining the December 2000 finding, removing coal and oil-fired Utility Units from the section 112(c) list, and regulating Hg emissions from Utility Units under CAA section 112(n)(1)(A).

Shortly thereafter, on March 16, 2004, EPA published in the **Federal Register** a supplemental notice of proposed rulemaking entitled ''Supplemental Notice of 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.'' *See* 69 FR 13298 (March 16, 2004). In that

[6] Section IV below addresses our conclusion that it is not appropriate and necessary to regulate coal- and oil-fired Utility Units under section 112 and explains why we now believe that our December 2000 finding lacked foundation. As explained below, one of the reasons the December 2000 ''appropriate'' finding for oil-fired Utility Units lacks foundation is because the record that was before the Agency in December 2000 establishes that Hg is a HAP of concern only as emitted from coal-fired units, not oil-fired units. Utility Study ES–5,13,27. EPA therefore should not have relied upon Hg emissions as a basis for finding it was appropriate to regulate oil-fired units under section 112. (*See, e.g.,* Utility Study ES–5, ES–27.)

[7] The ''appropriate'' finding for oil-fired units stemmed primarily from EPA's concerns over the potential health effects of nickel from such units. As explained in the January 2004 proposed rule, the record before the Agency in December 2000 supported a distinction between nickel and the other HAP emitted from oil-fired units. *See* 69 FR 4688. We proposed that this distinction was reasonable based on the relative amount of nickel emitted from oil-fired units and the health effects associated with such emissions. (See also Utility Study at ES–12 (noting higher population concentrations surrounding oil-fired units). At the time of the proposed rule, we recognized, however, the uncertainties in the data underlying our ''appropriate'' finding for oil-fired units based on nickel emissions, and for that reason solicited information as to whether nickel emissions from oil-fired plants currently pose a hazard to public health.

[8] We did not propose revising the December 2000 finding for gas-fired Utility Units because EPA continues to believe that regulation of such units under section 112 is not appropriate and necessary. We have not received any information that would cause us to change our conclusion in this regard. In fact, the information that we have received since the Utility Study only confirms the conclusion we reached in December 2000. We therefore take no action today with regard to the December 2000 finding for gas-fired Utility Units.

notice, EPA proposed certain additional regulatory text, which largely governed the proposed section 111 standards of performance for Hg, which included a cap-and-trade program. The supplemental notice also proposed state plan approvability criteria and a model cap-and-trade rule for Hg emissions from coal-fired Utility Units. The Agency received thousands of comments on the proposed rule and supplemental notice.[9] Comments relating to the central issues concerning today's action are addressed in this preamble. The remainder of our responses are contained in the response to comments document which is in the docket.[10]

D. The December 2004 Notice of Data Availability

On December 1, 2004, EPA published in the **Federal Register** a notice of data availability entitled ''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: Notice of Data Availability.'' *See* 69 FR 69864 (December 1, 2004). EPA issued this notice to seek additional information and input concerning: (1) Certain Hg data and information that the Agency received in response to the proposed rule and supplemental notice, (2) the different forms of Hg that are emitted into the atmosphere from coal-fired Utility Units and how those forms respond to different control technologies; and (3) a revised proposed benefits methodology for assessing the benefits of Hg regulation. The benefits methodology generally involves analyzing Hg emissions from coal-fired Utility Units, conducting deposition modeling based on the identified Hg emissions, and relating that deposition modeling to methylmercury concentrations in fish. EPA conducts benefits analyses for rulemakings consistent with the provisions of Executive Order 12866.

[9] We initially estimated that we had over 680,000 submissions from the public on the proposed rule and the supplemental notice, which came primarily in the form of letters and e-mails. A recent review of the electronic docket reveals that our initial estimate was over-stated. The docket reflects approximately 500,000 separate submissions from the public, about 5,000 of which represent unique comments.

[10] The response to comments document relevant to this rule is called: ''Response to Significant Public Comments Concerning the Proposed Revision of the December 2000 Appropriate and Necessary Finding and Proposed Removal of Utility Units From the Section 112(c) List.''

III. EPA's Interpretation of CAA Section 112(n)(1)(A)

As explained above, Congress treated Utility Units differently from other major and area sources and provided EPA considerable discretion in evaluating whether to regulate Utility Units under section 112. Section 112(n)(1)(A) provides, in full:

> 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 the date of the enactment of the Clean Air Act Amendments of 1990. The Administrator shall develop and describe in the Administrator's report to Congress alternative control strategies for emissions which may 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.
>
> (Emphasis added.).

The italicized terms in the above paragraph are central terms in section 112(n)(1)(A). Before we address our interpretation of these terms, however, we again summarize the requirements of section 112(n)(1)(A). The first step under section 112(n)(1)(A), which is addressed by the first three sentences of section 112(n)(1)(A), concerns the completion of a study and submission of the results of that study to Congress by November 15, 1993. The study is to examine the hazards to public health from utility HAP emissions that are reasonably anticipated to occur following imposition of the requirements of the CAA and to identify alternative control strategies for those HAP that may warrant regulation under section 112. The second step, which is addressed by the last sentence of section 112(n)(1)(A), requires EPA to determine whether regulation of Utility Units under section 112 is appropriate and necessary considering, among other things, the results of the study. Congress provided no deadline by which this determination must be made.

Section 112(n)(1)(A) itself contains no clear standard to govern EPA's analysis and determination of whether it is ''appropriate and necessary'' to regulate utilities under section 112. The first sentence of the subparagraph describes the scope of the study EPA was to conduct. The sentence on EPA's ''appropriate and necessary'' finding then says that the Agency must make that finding after considering the results of the study. But Congress did not supply an actual definition or test for determining whether regulation of utilities under section 112 is ''appropriate and necessary.'' Thus, EPA must supply a reasonable interpretation of those terms to fill the gap. *Chevron USA Inc.* v. *NRDC*, 467 U.S. 837 (1984).

Congress' direction on the study provides the only guidance in section 112(n)(1)(A) about the substance of EPA's inquiry. Because the statute provides no other explicit guidance, EPA has chosen to extrapolate from Congress' description of the study to adopt a reasonable interpretation of the phrase ''appropriate and necessary.'' The following sections describe how the Agency has used Congress' guidance on the study to formulate different aspects of our interpretation and application of the ''appropriate and necessary'' test.

A. Hazards to Public Health Reasonably Anticipated To Occur

In section 112(n)(1)(A), Congress directed EPA to perform a study of ''hazards to public health'' that would likely result from utility HAP emissions, before making any further decisions about regulating utilities under section 112. Unlike other sections of the CAA, section 112(n)(1)(A) focuses only on hazards to public health. It does not require that EPA study other factors, such as environmental effects without any established pathways to human health effects. In contrast, section 112(n)(1)(B) requires a separate EPA study, although not as a precursor to a regulatory determination, of the ''health and environmental effects'' of ''mercury emissions'' from a broad range of sources. Also unlike Section 112(n)(1)(A), many of the other requirements of section 112 explicitly require both an assessment of human health effects and, in addition, an assessment of adverse environmental effects. For example, the Administrator is charged with periodically reviewing the list of Hazardous Air Pollutants and adding pollutants that present a threat of either ''adverse human health effects'' or ''adverse environmental effects.'' CAA Section 112(b)(2). The Administrator examines area sources of HAPs to determine if they present ''a threat of adverse effects to human health or the environment.'' CAA Section 112(c)(3). The Administrator is to prioritize action under section 112(d) after considering ''the known or anticipated adverse effects of such pollutants on public health and environment.'' CAA Section 112(e)(2)(A). Nor did Congress appear to view the two terms as synonymous. Under section 112(f), the EPA

promulgates emission standards at a level ''with an ample margin of safety'' to ''protect public health.'' CAA Section 112(f)(2)(A). The Administrator may go further and impose more stringent standards to protect against ''an adverse environmental effect'' only after considering ''cost, energy, safety, and other relevant factors.'' *Id.*

As described above, section 112(n)(1)(A) also provides no clear standard for analyzing public health effects—in contrast to, for example, section 112(f). Under section 112(f), the issue is whether additional regulation is needed to ''provide an ample margin of safety to protect public health.'' Section 112(f) also expressly incorporates EPA's pre-1990 two-part inquiry for evaluating what level of emission reduction is needed to provide an ample margin of safety to protect public health. See CAA section 112(f)(2)(B) (incorporating EPA's two-part ample margin of safety inquiry, set forth at 54 FR 38044 September 14, 1989, which implemented the requirements of section 112 of the 1977 CAA).[11] By contrast, section 112(n)(1)(A) neither includes the ''ample margin of safety to protect public health'' requirement, nor does it incorporate EPA's pre-1990 ample margin of safety inquiry.

Because of the focus on ''public health'' in the section 112(n)(1)(A) study requirement, and because as discussed above Congress did not define the scope of the ''appropriate and necessary'' finding, EPA is reasonably interpreting section 112(n)(1)(A) to base that finding on an assessment of whether utility HAP emissions likely would result in ''hazards to public health.''

Moreover, EPA reasonably interprets section 112(n)(1)(A) not to require the Agency either to study or to base its ''appropriate and necessary'' finding on an assessment of environmental effects unrelated to public health.

As described above, Section 112(n)(1)(A) requires only that the Administrator ''consider'' the results of the public health study before determining whether utility regulation is ''appropriate and necessary.'' This mild direction, when paired with the considerable discretion inherent in any judgment about whether an action is ''appropriate and necessary,'' has led EPA to conclude that the statute permits the agency to consider other relevant factors when determining whether to regulate emissions from utility units under section 112. This is not to say, however, that EPA believes it may ignore the context of section 112(n) in making its determination.

The Supreme Court has recognized that ''where Congress includes particular language in one section of a statute but omits it in another section of the same Act,'' as here, where section 112(n)(1)(A) refers to public health and conspicuously omits any reference to adverse environmental effect, ''it is generally presumed that Congress acts intentionally * * * in the disparate inclusion or exclusion.'' *Russello* v. *United States,* 464 U.S. 16, 23 (1983). The only direction that Congress explicitly provided to guide our ''appropriate and necessary'' finding was that we consider the results of a study of only those ''hazards to public health'' that the agency ''reasonably anticipate[s] to occur.''

EPA must reconcile the broad discretion to determine what is ''appropriate and necessary'' with the implicit Congressional decision that information about environmental effects unrelated to human health effects was not needed for that determination. Rather than conclude that EPA is prohibited from considering environmental effects, however, EPA interprets section 112(n)(1)(A) to permit the agency to consider other relevant factors as part of its ''appropriate and necessary'' determination, as refined further below, but these factors may not independently, or in conjunction with one another, justify regulation under section 112(n) when EPA has concluded that hazards to U.S. public health are not reasonably anticipated to occur. Compare CAA section 112(f)(2)(A) (Administrator may set a more stringent standard than is required to protect health if necessary, considering factors such as cost, to prevent an adverse environmental effect).

In evaluating hazards to public health under section 112(n)(1)(A) we look at various factors, including, for example, the affected population, the characteristics of exposure (*e.g.,* level and duration), the nature of the data, including the uncertainties associated with the data, and the nature and degree of health effects. In terms of assessing health effects, we have numerous tools at our disposal. See Section VI.H (for fuller discussion of factors relevant to assessing the hazards to public health). For example, for cancer effects, we can assess the lifetime excess cancer risk, and for other effects, we look to tools, such as the reference dose.[12] As explained below, the ''hazards to public health reasonably anticipated to occur'' standard is relevant not only for the Study, but also for the appropriate and necessary determination.

EPA has also taken note of the context for assessing ''hazards to public health,'' for the language of section 112(n)(1)(A), calls for an analysis of the ''hazards to public health'' reasonably anticipated to ''occur as a result of emissions by electric utility steam generating units.'' (Emphasis added.) Section 110(a)(2)(D) provides an instructive comparison in this regard. In section 110(a)(2)(D), Congress required that each state implementation plan contain adequate provisions ''prohibiting * * * any source or other type of emissions activity within the State from emitting any air pollutant in amounts'' that will ''contribute significantly to nonattainment'' of the national ambient air quality standards. This provision demonstrates that Congress knew how to require regulation of emissions of air pollutants even where the pollutants themselves do not cause a problem, but rather only ''contribute to a problem.'' Unlike section 110(a)(2)(D), in section 112(n)(1)(A), Congress focused exclusively on the ''hazards to public health'' of HAP emissions ''result[ing] from'' Utility Units. Rather, it is the EPA study performed pursuant to section 112(n)(1)(B), not the inquiry under section 112(n)(1)(A), that examines all current anthopogenic sources of Hg emissions and their effects on human health and the environment. EPA has concluded that its inquiry under section 112(n)(1)(A) may reasonably focus solely on whether the utility HAP emissions themselves are posing a hazard to public health. This focus on utility emissions only is consistent with Congress' overall decision to provide for separate treatment of utilities in section 112(n)(1)(A).

B. Imposition of the Requirements of This Act

Congress required EPA to examine the hazards to public health from utility emissions ''after imposition of the requirements of this Act.'' The phrase ''imposition of the requirements of th[e] Act'' is susceptible to different

[11] Section 112 of the 1977 CAA directed EPA to promulgate emission standards ''at the level which in * * * [the Administrator's judgment] provides an ample margin of safety to protect the public health.'' Congress substantially amended section 112 in 1990 and enacted several new provisions. Congress specifically incorporated the ''ample margin of safety to protect public health'' requirement into section 112(f), which applies to any source category that is regulated under section 112(d)(2) and (d)(3). Significantly, Congress did not include the ''ample margin of safety'' language in section 112(n)(1)(A). Instead, Congress directed EPA to assess the ''hazards to public health reasonably anticipated to occur'' from utility HAP emissions after imposition of the requirements of the CAA, and then determine whether Utility unit emissions should be regulated under section 112 of the CAA.

[12] Section VI below discusses the reference dose (''RfD'') in detail.

interpretations because Congress did not specify the scope of the requirements under the CAA to be considered or, more importantly, the time period over which the imposition of requirements was to be examined. EPA reasonably interprets the phrase ''imposition of the requirements of th[e] Act'' to include not only those requirements already imposed and in effect, but also those requirements that EPA reasonably anticipates will be implemented and will result in reductions of utility HAP emissions. This interpretation is reasonable in view of the fact that Congress called for the study to be completed within three years of enactment of the 1990 CAA Amendments. At such time, EPA could have only forecast, to the extent possible, how implementation of the requirements of the CAA would impact utility HAP emissions, based on the science and the state of technology at the time.[13]

We are interpreting the phrase ''requirements of th[e] Act'' broadly to include CAA requirements that could either directly or indirectly result in reductions of utility HAP emissions. For example, certain provisions of the CAA that affect Utility Units, such as the requirements of Title I and Title IV, require controls on pollutants like SO_2 or NO_X. Although these pollutants are not HAP, the controls that are required to achieve the needed reductions have the added effect of reducing HAP emissions. Thus, given our interpretation of the phrase ''imposition of the requirements of th[e] Act,'' we read the first sentence of section 112(n)(1)(A) as calling for a study of the hazards to public health from utility HAP emissions that EPA reasonably anticipates would occur after implementation of the CAA requirements that EPA, at the time of the study, should have reasonably anticipated would be implemented and would directly or indirectly result in reductions of utility HAP emissions.

Finally, it is telling that Congress directed EPA to examine the utility HAP emissions remaining ''after imposition of the requirements of th[e] Act,'' because there is no other provision in section 112 that calls for EPA to examine the requirements of the CAA in assessing whether to regulate a source category under section 112.[14] Congress plainly treated Utility Units differently from other source categories, and that special treatment reveals Congress' recognition that Utility Units are a broad, diverse source category that is subject to numerous CAA requirements, including requirements under both Title I and Title IV, and that such sources should not be subject to duplicative or otherwise inefficient regulation.[15] See 136 Cong. Rec. H12911, 12934 (daily ed. Oct. 26, 1990) (Statement of Congressman Oxley) (stating that the conferees adopted section 112(n)(1)(A) ''because of the logic of basing any decision to regulate on the results of scientific study and because of the emission reductions that will be achieved and the extremely high costs that electric utilities will face under other provisions of the new Clean Air Act amendments.'').

C. Appropriate and Necessary After Considering the Results of the Study

Section 112(n)(1)(A) requires EPA to make a determination as to whether regulation of Utility Units under section 112 is ''appropriate and necessary.'' Congress did not define the terms ''appropriate'' and ''necessary,'' but provided that regulation of Utility Units under section 112 could occur only if EPA determines that such regulation is both ''appropriate'' and ''necessary.''

1. Considering the Results of the Study

The appropriate and necessary determination is to be made only after ''considering the results of the study'' required under section 112(n)(1)(A). We interpret the phrase ''considering the results of the study'' to mean that EPA must consider the results of the study in making its determination, but that EPA is not foreclosed from analyzing other relevant information that becomes available after completion of the study. This interpretation is reasonable because section 112(n)(1)(A) contains no deadline by which EPA must determine whether it is ''appropriate and necessary'' to regulate Utility Units under section 112.

Moreover, nothing in section 112(n)(1)(A) suggests that EPA is precluded from considering new relevant information obtained after completion of the Utility Study in determining whether regulation of Utility Units under section 112 is appropriate and necessary. Indeed, the term ''considering'' in section 112(n)(1)(A) is analogous to the terms ''based on'' or ''including,'' which are neither limiting nor exclusive terms.[16] In a recent case, the DC Circuit rejected an argument advanced by the petitioners that an EPA rule was invalid because the statute required EPA to promulgate the regulation ''based on the study,'' and according to petitioners EPA's rule was not based on a study that met the requirements of the CAA. *Sierra Club* v. *EPA*, 325 F.3d 374 (DC Cir. 2003). In rejecting petitioners' arguments, the Court held, among other things, that ''the statute doesn't say that the rule must be based exclusively on the study.'' *Sierra Club* v. *EPA*, 325 F.3d at 377 (emphasis in original); See also *United States* v. *United Technologies Corp.*, 985 F.2d 1148, 1158 (2d Cir. 1993) (''based upon'' does not mean ''solely''); *McDaniel* v. *Chevron Corp.*, 203 F.3d 1099, 1111 (9th Cir. 2000). Consistent with this reasoning, EPA reasonably interprets the phrase ''considering the results of the study,'' to mean that EPA must consider the study, but that it can consider other relevant information obtained after completion of the study. Congress could not have reasonably intended for EPA to

[13] Although the December 2000 finding does not provide an interpretation of the phrase ''after imposition of the requirements of the[e] Act,'' the Utility Study, on which that finding was based, does account for the phrase by evaluating utility HAP emission levels in 2010. See Utility Study ES–2 (the ''2010 scenario was selected to meet the section 112(n)(1)(A) mandate to evaluate hazards 'after imposition of the requirements of 'the CAA.''). We do not believe that the December 2000 finding or the January 2004 proposal properly give effect to all of the terms of section 112(n)(1)(A), including the first sentence of section 112(n)(1)(A). We therefore provide our interpretation of the central terms in that sentence above, as those terms are relevant to the final actions we are taking today.

[14] Section 112(m)(6) provides an instructive comparison because it requires EPA to examine the other provisions of section 112, and to determine whether those provisions are adequate to prevent serious adverse effects to public health and the environment associated with atmospheric deposition to certain waterbodies. Section 112(m)(6) also requires EPA to promulgate additional regulations setting emission standards or control requirements, ''in accordance with'' section 112 and under the authority of section 112(m)(6), if EPA determines that the other provisions of section 112 are adequate, and such regulations are appropriate and necessary to prevent serious adverse public health and environmental effects. Section 112(n)(1)(A) provides EPA far greater discretion because under that section, EPA is not only to evaluate the reasonably anticipated public health hazards remaining ''after imposition of the requirements of th[e] Act,'' but also to determine whether to regulate Utility Units under section 112 of the CAA at all.

[15] As noted elsewhere, section 112(n)(1)(A) was included in the House Committee bill and adopted by the House; while the Senate included a different provision. In the Conference Committee, the House version prevailed. Sen. Durenberger, a Senate conferee and an evident opponent of the provision, alluded to another purpose for the provision, which concerns the fact that ''mercury is a global problem.'' Legislative History of the Clean Air Act Amendments of 1990, at 872 (Oct. 27, 1990) (statement of Sen. Durenberger). Based on Sen. Durenberger's statement, it appears that one of the reasons for the wide deference Congress accorded EPA under section 112(n)(1)(A) was to allow EPA to account for the fact that Hg emissions from U.S. utilities are a very small part of overall Hg emissions, and therefore that EPA should exercise discretion in considering the uncontrollable amount of risk from Hg that would remain regardless of the extent to which U.S. utilities are controlled.

[16] In fact, the term ''considering,'' on its face, is less limiting than the phrase ''based on.''

ignore relevant information concerning HAP emissions from Utility Units solely because that information was obtained after completion of the Utility Study.[17]

2. Appropriate and Necessary

The condition precedent for regulating Utility Units under section 112 is whether such regulation is ''appropriate'' and ''necessary.'' These are two very commonly used terms in the English language, and Congress has not ascribed any particular meaning to these terms in the CAA. The legislative history does not resolve Congress' intent with regard to these terms. We therefore first examine the structure of section 112(n)(1)(A) and then discuss our interpretation of the terms ''appropriate'' and ''necessary.''

a. Examining the Structure of Section 112(n)(1)(A). In interpreting the terms ''appropriate'' and ''necessary'' in section 112(n)(1)(A), we begin with the structure of section 112(n)(1)(A). As an initial matter, the order of the terms in the phrase ''appropriate and necessary'' suggests that the first decision EPA must make is whether regulation of Utility Units under section 112 is ''appropriate.'' Even if EPA determines that regulation of Utility Units under section 112 is appropriate, it must still determine whether such regulation is also necessary. Were EPA to find, however, that regulation of Utility Units under section 112 met only one prong, then regulating Utility Units under section 112 would not be authorized by the statute.

The structure of section 112(n)(1)(A) also reveals that the appropriate and necessary finding is to be made by reference to the reasonably anticipated public health risks of utility HAP emissions that remain after ''imposition of the requirements of th[e] Act.'' The first sentence of section 112(n)(1)(A) contains an important direction to EPA, which sets the predicate for the entire provision. That first sentence calls for EPA to identify the hazards to public health reasonably anticipated to occur as a result of the utility HAP emissions remaining ''after imposition of the requirements of th[e] Act.'' Stated differently, Congress wanted EPA to identify the utility HAP emissions that would remain ''after imposition of the requirements of th[e] Act'' and identify the hazards to public health reasonably anticipated to occur as the result of such emissions. As noted above, we interpret the phrase ''imposition of the requirements of th[e] Act'' to include those CAA requirements that EPA should have reasonably anticipated would be implemented and would result in reductions of utility HAP emissions.[18] Congress' focus on the other requirements of the CAA reflects its recognition that Utility Units are subject to numerous CAA provisions and its intent to avoid duplicative and unnecessary regulation. We therefore reasonably conclude that the appropriate and necessary finding is to be made by reference to the reasonably anticipated public health risks from utility HAP emissions that remain ''after imposition of the requirements of th[e] Act.''

b. EPA's interpretations of the terms ''appropriate'' and ''necessary.'' (i) Appropriate. In December 2000, EPA found that it was appropriate to regulate coal- and oil-fired Utility Units under section 112. At that time, we did not provide an interpretation of the term ''appropriate.'' Instead, we focused on the following facts and circumstances. We first found that it was ''appropriate'' to regulate coal- and oil-fired Utility Units under section 112 because ''mercury in the environment presents significant hazards to public health.'' *See* 65 FR 79830. We also determined that it was appropriate to regulate oil-fired Utility Units based on the uncertainties ''regarding the extent of the public health impact from HAP emissions from'' such units. *See* 65 FR 79830. Finally, we found that it was appropriate to regulate HAP emissions from coal-and oil-fired units under section 112 because we had identified control options that we anticipated would effectively reduce certain HAP emissions. We also indicated that certain control options could ''greatly reduc[e] mercury control costs.'' *See* 65 FR 79830.

In January 2004, we proposed reversing our ''appropriate'' finding in large part. Specifically, we proposed that it is not ''appropriate'' to regulate coal-fired units on the basis of non-Hg HAP and oil-fired units on the basis of non-Ni HAP because the record that was before the Agency in December 2000 indicates that emissions of such pollutants do not result in hazards to public health. *See* Section IV.B.

Webster's dictionary defines the term ''appropriate'' to mean ''especially suitable or compatible.'' Miriam-Webster's Online Dictionary, 10th ed. Determining whether something is ''especially suitable or compatible'' for a particular situation requires consideration of different factors. In section 112(n)(1)(A), Congress requires EPA to determine whether it is ''appropriate'' to regulate Utility Units under section 112. In making this determination, we begin as we did in December 2000, by assessing the paramount factor, which is whether the level of utility HAP emissions remaining ''after imposition of the requirements of th[e] Act'' would result in hazards to public health. We determine whether the remaining utility HAP emissions cause hazards to public health by analyzing available health effects data and assessing, among other things, the uncertainties associated with those data, the weight of the scientific evidence, and the extent and nature of the health effects. See Section VI. If the remaining HAP emissions from Utility Units do not result in hazards to public health, EPA does not believe that it would be ''especially suitable''—*i.e.*, ''appropriate''—to regulate such units under section 112. In this situation, there would be no need to consider any additional factors under the ''appropriate'' inquiry because the threshold fact critical to making a finding that it is appropriate to regulate Utility Units under section 112 would be missing.

Even if the remaining utility HAP emissions cause hazards to public health, it still may not be appropriate to regulate Utility Units under section 112 because there may be other relevant factors particular to the situation that would lead the Agency to conclude that it is not ''especially suitable'' or ''appropriate'' to regulate Utility Units under section 112. For example, it might not be appropriate to regulate the utility HAP emissions remaining ''after imposition of the requirements of th[e] Act,'' if the controls mandated under section 112(d) would be ineffective at eliminating or reducing the identified hazards to public health. Similarly, it might not be appropriate to regulate the

[17] Consistent with this interpretation, in December 2000, EPA relied not only on the Utility Study, but also on certain information concerning Hg obtained after completion of the study, including actual emissions data from coal-fired plants for calendar year 1999 and a report from the National Academy of Sciences on the health effects of methylmercury. See 65 FR 79825–27.

[18] The comments of Rep. Oxley, a member of the Conference Committee, about section 112(n)(1)(A) support EPA's interpretation of that provision. Rep. Oxley stated:

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 on the public health. Thus, if the Administrator regulates any of these units, he may regulate only those units that he determines—*after taking into account compliance with all other provisions of the CAA* and any other federal, state or local regulation and voluntary emission reductions—have been demonstrated to cause a significant threat of adverse effects on public health.

136 Cong. Rec. H12911, 12934 (daily ed. Oct. 26, 1990) (Statement of Rep. Oxley) (emphasis added).

remaining utility HAP emissions under section 112 if the health benefits expected as the result of such regulation are marginal and the cost of such regulation is significant and therefore substantially outweighs the benefits. These examples illustrate that situation-specific factors, including cost, may affect whether it ''is appropriate'' to regulate utility HAP emissions under section 112.[19] (See Section 112(n)(1)(A).)

It cannot be disputed that Congress under section 112(n)(1)(A) entrusted EPA to exercise judgment by evaluating whether regulation of Utility Units under section 112 is, in fact, ''appropriate.'' We believe that in exercising that judgment, we have the discretion to examine all relevant facts and circumstances, including any special circumstances that may lead us to determine that regulation of Utility Units under CAA section 112 is not appropriate.[20]

(ii) Necessary. Like the ''appropriate'' finding, the ''necessary'' finding must be made by reference to the utility HAP emissions remaining after imposition of the requirements of the CAA.

Specifically, we interpret the term ''necessary'' in section 112(n)(1)(A) to mean that it is necessary to regulate Utility Units under section 112 only if there are no other authorities available under the CAA that would, if implemented, effectively address the remaining HAP emissions from Utility Units. Assessing whether an alternative authority would effectively address the remaining utility HAP emissions would involve not only: (a) An analysis of whether the alternative legal authority, if implemented, would address the identified hazards to public health, which was a concept specifically addressed in December 2000 and in the January 2004 proposal, but also (b) an analysis of whether the alternative legal authority, if implemented, would result in effective regulation, including, for example, its cost-effectiveness and its administrative effectiveness. See *Michigan* v. *EPA*, 213 F.3d, 663, 678 (addressing consideration of costs).

This interpretation of the term ''necessary'' differs slightly from the interpretation advanced in December 2000 and January 2004. In December 2000 and January 2004, we interpreted the term ''necessary'' to mean that it is only necessary to regulate Utility Units under section 112 if there are no other authorities under the CAA that would adequately address utility HAP emissions. Several commenters noted that under this interpretation, EPA could never regulate HAP under section 112 if it identified an alternative viable legal authority. In light of these comments and further review of section 112(n)(1)(A), we refined our interpretation of the term ''necessary'' as noted above. We agree that if we found an alternative authority under the CAA but we also determined that such authority would not effectively address the remaining HAP emissions, we should be able to address those emissions under section 112. Accordingly, we maintain that it is necessary to regulate Utility Units under section 112 only if there are no other authorities under the CAA that, if implemented, would effectively address the remaining HAP emissions from Utility Units.

Some commenters argued that the ''appropriate and necessary'' finding is a public health threshold finding, not an investigation into whether another provision of the CAA would address HAP emissions from utilities. This argument is without merit, however, because it conflates the terms ''appropriate'' and ''necessary'' and renders one term mere surplusage. Congress required EPA to determine whether it was both appropriate and necessary to regulate Utility Units under section 112. EPA agrees that it must evaluate the hazards to public health associated with HAP from utilities in terms of assessing whether regulation under section 112 is ''appropriate.'' But Congress meant something different by the term ''necessary,'' and EPA's interpretation of that term is reasonable. Moreover, we believe that the emissions inquiry envisioned under the first sentence of section 112(n)(1)(A) is distinct from the ''necessary'' inquiry called for by the last sentence of section 112(n)(1)(A), because under the ''necessary'' inquiry the issue is not whether EPA reasonably anticipated that a particular provision of the CAA will be implemented and will reduce HAP emissions, but rather whether there are any other authorities in the CAA that could be implemented, and if implemented, could effectively address the hazards to public health that result from the remaining HAP emissions.

Other commenters argued that EPA cannot consider other statutory authorities under the ''necessary'' prong of the ''appropriate and necessary'' inquiry because those authorities do not provide for regulation of utility HAP according to the provisions of CAA section 112(d) and (f). This argument is also without merit because it again renders mere surplusage the ''necessary'' prong of the determination. Moreover, as explained above, Congress did not incorporate the requirements of section 112(f) into section 112(n)(1)(A), but instead, as we interpret section 112(n)(1)(A), called on EPA to consider the ''hazards to public health reasonably anticipated to occur'' from utility HAP emissions after imposition of the requirements of the CAA, in determining whether it is both appropriate and necessary to regulate Utility Units under section 112.

3. The Timing and Nature of the ''Appropriate and Necessary'' Determination

Congress set no deadline in section 112(n)(1)(A) by which EPA must determine whether regulation of Utility Units is appropriate and necessary. We believe that Congress provided

[19] Nothing precludes EPA from considering costs in assessing whether regulation of Utility Units under section 112 is appropriate in light of all of the facts and circumstances presented. The DC Circuit has indicated that regulatory provisions should be read with a presumption in favor of considering costs: ''It is only where there is 'clear congressional intent to preclude consideration of cost' that we find agencies barred from considering costs. [Citations omitted.]'' *Michigan* v. *EPA*, 213 F.3d 663, 678 (DC Cir. 2000), cert. den., 532 U.S. 903 (2001) (upholding EPA's interpretation of ''contribute significantly'' under CAA section 110(a)(2)(D) to include a cost component). The Supreme Court's decision in *Whitman* v. *American Trucking Assn's (ATA)*, Inc., 531 U.S. 457 (2001), is not to the contrary. In that case, the Court held that EPA lacked authority to consider costs in the context of setting the national ambient air quality standards under CAA section 109(b)(1), because the ''modest words 'adequate margin' and 'requisite' '' in that section do not ''leave room'' to consider cost. 531 U.S. 466. By contrast, EPA is not setting emission standards in today's action, but rather determining, as Congress directed, whether it is ''appropriate'' and ''necessary'' to regulate Utility Units under CAA section 112. The terms ''appropriate'' and ''necessary'' are broad terms, which by contrast to the terms at issue in ATA do, in fact, leave room for consideration of costs in deciding whether to regulate utilities under section 112. Moreover, the legislative history of section 112(n) indicates that Congress intended for EPA to consider costs. See 136 Cong. Rec. H12911, 12934 (daily ed. Oct. 26, 1990) (statement of Rep. Oxley) (''[T]he conference committee produced a utility air toxics provision that will provide ample protection of the public health while avoiding the imposition of excessive and unnecessary costs on residential, industrial and commercial consumers of electricity.''). Finally, section 112(n)(1)(A) requires EPA to consider alternative control strategies, and the focus on such strategies may reasonably be read as further evidence of the relevance of costs. *See, e.g.*, 65 FR 79830 (discussing costs in relation to certain technologies).

[20] Significantly, in December 2000, we acknowledged that factors other than the hazards to public health resulting from utility HAP emissions should be examined in determining whether regulation of Utility Units is appropriate under section 112. Indeed, after concluding that the Hg emissions from coal-fired Utility Units caused hazards to public health, we proceeded with the appropriate inquiry and examined whether there were any control technologies that could effectively reduce Hg. We also commented on the costs of achieving such reductions. *See, e.g.*, 65 FR 79828, 79830.

sufficient discretion under section 112(n)(1)(A)—in terms of both the substance and the timing of the appropriate and necessary finding—that nothing precludes us from revising our appropriate and necessary finding if we determine either that the finding was in error based on information before the Agency at the time of the finding, or that the finding is incorrect given new information concerning utility HAP emissions obtained after issuance of the finding. Both of these situations are present here, as explained in section IV below.

Moreover, EPA reasonably interprets the last sentence of section 112(n)(1)(A) as authorizing EPA to issue separate appropriate and necessary findings for different subcategories of ''electric utility steam generating units.'' EPA typically subcategorizes large source categories such as utilities. This is especially true for Utility Units because the nature of the fuel used in different units (*e.g.,* coal-, oil-, or gas-fired Utility Units), affects the type and amount of HAP emitted from the units, which, in turn, affects the issue of whether hazards to public health may exist from such emissions.[21] Even where section 112(n)(1)(A) read to require EPA to make only one appropriate and necessary finding for all ''electric utility steam generating units,'' EPA's conclusions, as described below, would remain the same.

IV. Revision of the December 2000 Appropriate and Necessary Finding

In Section II above, we summarize the December 2000 appropriate and necessary finding for coal- and oil-fired Utility Units. In this section, we explain why we now believe that the December 2000 finding lacked foundation and therefore was erroneous. We also address below certain new information obtained since the finding that confirms that it is not appropriate and necessary to regulate coal- and oil-fired Utility Units under section 112. Our discussion below is divided into two sections, the first of which concerns the December 2000 finding for coal-fired units, and the second of which addresses the December 2000 finding for oil-fired units.

A. Revision of the December 2000 Appropriate and Necessary Finding for Coal-fired Units

The majority of the December 2000 finding concerned Hg emissions from coal-fired Utility Units. *See, e.g.*, 65 FR 79826 (''mercury * * * is emitted from coal-fired units, and * * * is the HAP of greatest concern to public health from the industry.''); 65 FR 79829–30 (conclusions section of December 2000 finding focuses almost exclusively on Hg); Utility Study, ES–27 (''mercury from coal-fired utilities is the HAP of greatest potential concern.''). For that reason, we first address how EPA erred in making the appropriate and necessary finding for coal-fired units based on Hg emissions. We then discuss the December 2000 finding for coal-fired units with regard to non-Hg HAP.

1. It Is Not Appropriate and Necessary To Regulate Coal-Fired Units on the Basis of Hg Emissions

a. It Is Not Appropriate to Regulate Coal-fired Units on the Basis of Hg Emissions. As noted above, EPA's December 2000 ''appropriate'' finding is framed primarily in terms of health effects resulting from Hg emissions from coal-fired Utility Units.[22] *See* 65 FR 79829. The December 2000 finding also discusses environmental effects, primarily in the context of public health. In particular, the appropriate finding discusses the effects of Hg on fish because the public's primary route of exposure to Hg is through consumption of fish containing methylmercury. *See* 65 FR 79829–30. *See also* Section VI (discussing health effects of Hg). The December 2000 finding also discusses briefly the effects of methymercury on certain fish-eating wildlife, such as racoons and loons. See 65 FR 79830.

As explained above, EPA interprets section 112(n)(1)(A) as not requiring the Agency to consider environmental effects of utility HAP emissions that are unrelated to public health. Nevertheless, EPA believes it has authority under the ''appropriate'' inquiry to consider other factors, including non-public health related environmental factors. As explained above, however, given the focus in section 112(n)(1)(A) on hazards to public health, we believe that environmental factors unrelated to public health, although they can be considered in the appropriate inquiry, may not independently or, in conjunction with one another, justify regulation of Utility Units under section 112 when EPA has concluded that hazards to public health are not reasonably anticipated to result from utility HAP emissions.

EPA reasonably addressed non-public health related environmental factors, such as exposure to wildlife, in the December 2000 finding, because we separately concluded that Hg emissions from coal-fired Utility Units pose hazards to public health. As explained below, we believe that our December 2000 appropriate finding lacks foundation, and that conclusion is supported by certain recent information. Specifically, we conclude today that the level of Hg emissions remaining after imposition of the requirements of the Act will not cause hazards to public health, and therefore we need not consider other factors, such as non-public health related environmental effects. We do, of course, discuss the effects of Hg on fish, because the ingestion of fish contaminated with methylmercury is the public's primary route of exposure to Hg. See Section VI (discussing health effects of Hg).[23]

As noted above, EPA's December 2000 appropriate finding for coal-fired units hinged primarily on the health and environmental effects resulting from Hg emissions. *See* 65 FR 79830 (''mercury in the environment presents significant hazards to public health and the environment.''). This finding lacks foundation, however, for the reasons described below.

(i) The December 2000 Appropriate Finding Is Overbroad To The Extent It Hinged On Environmental Effects. EPA should not have made its appropriate

[21] We received no adverse comments concerning our subcategorization of Utility Units for purposes of section 112(n)(1)(A).

[22] The ''appropriate'' rationale set forth in the December 2000 finding focused exclusively on Hg with regard to coal-fired Utility Units. The December 2000 ''necessary'' finding can be read, however, to suggest that under the appropriate prong, EPA also determined that non-Hg from coal-fired Utility Units resulted in hazards to public health. See 65 FR 79830 (''*It is necessary to regulate HAP emissions from coal- and oil-fired*'' Utility Units under section 112 ''because the implementation of other requirements of the CAA will not address the serious public health and environmental hazards arising from such emissions.''). As explained below in section IV.B, the record that was before the Agency in December 2000 confirms that the non-Hg HAP emissions remaining ''after imposition of the requirements of th[e] Act'' do not result in hazards to public health. In the proposed rule, EPA solicited comment on this issue. We did not receive any new information concerning non-Hg HAP during the comment period that would cause us to change our position as to these HAP.

[23] We note, however, that as part of our overall inquiry into the effects of Hg emissions, we assessed the available information on the environmental effects of Hg emissions, including effects that appear to be unrelated to public health. See 1997 Mercury Report to Congress. While that information, in a very general sense, suggests that environmental effects of Hg emissions (unrelated to public health) may be of some concern and therefore warrant further study, the available information is not specific to the effects of Hg emissions from domestic utilities. See RIA Appendix C. Thus, even if EPA were either required or permitted to give unlimited consideration to these non-health-related environmental effects of utility Hg emissions in making the regulatory determination under section 112(n)(1)(A), we would conclude that there is insufficient causal information to conclusively link utility emissions to deleterious effects (in wildlife) from Hg exposure.

finding because of ''hazards to * * * the environment'' resulting from Hg emissions from coal-fired Utility Units. Section 112(n)(1)(A) requires EPA to analyze only the ''hazards to public health'' resulting from utility HAP emissions, not the environmental effects caused by such emissions. Under section 112(n)(1)(A), the condition precedent for regulation under section 112 is public health hazards, not environmental effects, which Congress included in other provisions of section 112. *See, e.g.*, 112(c)(3) (''a threat of adverse effect to human health or the environment.''). The Supreme Court has recognized that ''where Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally * * * in the disparate inclusion or exclusion.'' *Russello* v. *United States,* 464 U.S. 16, 23 (1983). Accordingly, EPA erred in its December 2000 ''appropriate'' finding to the extent that it hinged on the environmental effects of HAP, including Hg.

(ii) The December 2000 Appropriate Finding Lacks Foundation Because EPA Did Not Fully Consider The Hg Reductions That Would Result From ''Imposition of the Requirements of th[e] Act.'' As explained above, EPA interprets section 112(n)(1)(A) as providing that the ''appropriate'' finding should be made by reference to the level of HAP emissions remaining after ''imposition of the requirements of th[e] Act.'' We reasonably interpret the phrase ''imposition of the requirements of th[e] Act'' to include those requirements that EPA should have reasonably anticipated would be implemented and would result in reductions of utility HAP emissions.

The December 2000 ''appropriate'' finding lacks foundation because EPA failed to fully account for the Hg emissions remaining after ''imposition of the requirements of th[e] Act.'' [24] That failure resulted in an overestimate of the remaining utility Hg emissions, which is the level of emissions that we considered in making our December 2000 appropriate finding. Had we properly considered the Hg reductions remaining ''after imposition of the requirements of th[e] Act'' in December 2000, we might well have (and, as discussed below, now believe should have) reached a different conclusion as to whether it was ''appropriate'' to regulate coal-fired units on the basis of Hg emissions.

We begin our analysis with a brief background concerning the Utility Study. In an attempt to address the requirement in section 112(n)(1)(A) of evaluating utility emissions ''after imposition of the requirements of th[e] Act'', the Utility Study estimates utility HAP emissions as of the year 2010. See Utility Study ES–1. In quantifying 2010 utility HAP emissions, our analysis focused almost exclusively on the acid rain provisions of Title IV. Title IV of the CAA establishes a national, annual emissions cap for sulfur dioxide (SO_2) emissions from Utility Units, which is to be implemented in two phases. Phase I commences January 1, 1995, and Phase II on January 1, 2000.

EPA relied in the Utility Study on a 1997 Department of Energy report concerning the effects of the implementation of Title IV of the CAA on utilities. Utility Study 2–31 to 2–33, 2–39. That report provides that 53 percent of Utility Units subject to Phase 1 requirements switched to a lower-sulfur coal, 27 percent purchased additional emissions allowances, and 16 percent (*i.e.,* 27 Utility Units) installed flue gas scrubbers to comply with the Phase I requirements.[25] In the 2010 utility HAP emissions analysis, EPA accounted for the 27 Utility Units that installed scrubbers to comply with the phase I requirements. Utility Study 2–31. EPA accounted for these scrubbers in the 2010 analysis because it recognized that scrubbers, which control SO_2, achieve HAP reductions, including Hg.[26] Utility Study at ES–19 & 25, 1–2, 2–32, 3–14 (discussing ability of PM controls (including SO_2 controls) to reduce Hg and other HAP emissions from Utility Units).[27] Significantly, however, EPA did not incorporate into the 2010 utility HAP emissions analysis the Hg reductions that we reasonably should have anticipated achieving through implementation of the requirements of Title I of the CAA. See Utility Study, at 2–31 to 2–33. In this regard, EPA erred in, at least, two respects.

First, EPA erred by not accounting for the utility Hg reductions that it should have reasonably anticipated would result from implementation of the nonattainment provisions of Title I, including, in particular, the revised NAAQS for ozone that EPA issued in July 1997, before the report was completed, under the nonattainment provisions.[28] The Utility Study expressly recognizes that the revised NAAQS would result in, among other things, significant reductions of SO_2 and NO_X. See generally Utility Study at 1–2 to 1–3. The Utility Study also indicates that the revised NAAQS would result in approximately a 16 percent reduction (11 tons per year) of Hg emissions by 2010, primarily due to the fact that Utility Units would need to install controls, like scrubbers, to meet the SO_2 reductions needed to attain the PM NAAQS. (Utility Study 1–3, ES–25, 3–14). Notwithstanding these significant estimated reductions, EPA did not take these reductions into account in its 2010 utility HAP emissions analysis.[29] ES–25 (''analyses performed to assess compliance with the revised NAAQS * * * indicate that Hg emissions in 2010 may be reduced by approximately 16 percent (11 tpy) *over those projected in this report.*''). Accordingly, the December 2000 appropriate finding lacks foundation because we made the finding based on an inaccurate level of Hg emissions remaining after imposition of the requirements of the CAA. Had we properly accounted in December 2000 for the 11 tons per year of Hg reductions that we projected in our own analyses, we might well have (and, as discussed below, now believe should have) concluded that it was not appropriate to regulate coal-fired units under section

[24] For ease of reference, we refer to the level of utility Hg emissions remaining ''after imposition of the requirements'' of the CAA as the ''remaining Hg emissions.''

[25] Flue gas scrubbers are a type of control technology used to control SO_2.

[26] EPA did not account in its 2010 analysis for the installation of any scrubbers associated with Phase II of the acid rain program, because it only had industry projections as to which units would install scrubbers and, for various reasons, it did not find those projections reliable. Utility Study 2–31 to 2–33.

[27] In the December 2000 finding, we indicate that recent data show that technologies used to control criteria pollutants, like PM, SO_2, and NO_X are not ''effective'' in controlling Hg. See 65 FR 79828. This statement is incorrect. It is not only inconsistent with other statements in the December 2000 finding, it is contrary to the record that was before the Agency in December 2000. The record indicates that technologies used to control PM, SO_2, and NO_X do reduce HAP, including Hg. Furthermore, insofar as Hg is concerned, these technologies result in important reductions of oxidized Hg, which is the type of Hg that tends to deposit locally and regionally. Utility Study at ES–19 & 25, 1–2, 2–32, 3–14.

[28] For additional background concerning the nonattainment provisions of Title I and the revised PM and ozone NAAQS, see Section V below.

[29] In the Utility Study, we explained that we did not account for the identified Hg reductions in the 2010 analysis because we lacked information on the specific number of units that would install scrubbers and related PM control technologies since we had not yet designated which areas of the country were in nonattainment of the revised NAAQS. See Utility Study 2–32. Although we had not yet designated areas of the country as being in nonattainment of the revised standards, as explained in section V, we were generally aware of the likelihood of widespread nonattainment with the revised NAAQS. In fact, that recognition formed the basis of our analysis that resulted in an estimated 16 percent reduction in Hg emissions from implementation of the revised NAAQS.

112 on the basis of the remaining Hg emissions. Indeed, recent modeling confirms that we likely would have reached such a conclusion. That modeling specifically demonstrates that about a 13 ton reduction in utility Hg emissions from 1990 levels would result in a level of Hg emissions that does not cause hazards to public health. We conducted these recent analyses in conjunction with the recently signed Clean Air Interstate Rule (''CAIR'') issued pursuant to CAA section 110(a)(2)(D), which is explained more fully in section V below.

Second, EPA erred in December 2000 by not examining, and therefore not accounting for, the reductions in utility Hg emissions that would result from two other rules issued pursuant to Title I of the CAA. The first rule set new source performance standards (''NSPS'') under CAA section 111(b) for NO_X emitted from utility and industrial boilers. The second rule, promulgated under CAA section 110(a)(2)(D), requires 22 states and the District of Columbia to revise their state implementation plans (''SIP'') to mitigate for the interstate transport of ozone. This rule is called the NO_X SIP-call rule and requires significant reductions of NO_X emissions in the eastern half of the United States. EPA determined those NO_X reductions by analyzing Utility Units and large nonpoint utility sources and identifying the amount of reductions that those units could achieve in a ''highly cost-effective'' manner. Both the NO_X SIP call and the NSPS rule were premised on a NO_X control technology called selective catalytic reduction (''SCR''). The data on the effectiveness of SCR at controlling utility Hg emissions was limited in February 1998. See Utility Study 2–32. As of December 2000, however, EPA had additional data that confirmed that SCR would lead to certain reductions in utility Hg emissions. *See, e.g.,* 65 FR 79829 (SCR—a NO_X control technology ''may also oxidize mercury and therefore enhance mercury control.''). EPA therefore should have been able to reasonably estimate in December 2000 that some Hg reductions would occur as the result of implementation of the NSPS and the NO_X SIP-call rules. Because we did not account for reductions in utility Hg emissions as the result of implementation of these rules, we made our appropriate finding in December 2000 based on an incorrect estimate of the remaining Hg utility emissions. Based on all of the above, the December 2000 ''appropriate'' finding lacked foundation because it was not based on the level of utility Hg emissions remaining ''after imposition of the requirements of th[e] Act.''

(iii) It Is Not Appropriate to Regulate Coal-fired Utility Units Under Section 112 on the Basis of Hg Emissions Because New Information Reveals that the Level of Utility Hg Emissions Remaining After Imposition of the Requirements of the CAA Does Not Cause Hazards to Public Health. In addition to the errors noted above with regard to the December 2000 finding, we have new information that confirms that it is not appropriate to regulate coal-fired units under section 112 on the basis of Hg emissions. EPA recently signed a rulemaking implementing section 110(a)(2)(D), called the Clean Air Interstate Rule. (See Section V below for further discussion of CAIR.) This rulemaking, among other things, requires a number of eastern states to develop SIPs providing for substantial reductions of SO_2 and NO_X emissions. Although affected states retain flexibility to decide how to achieve those reductions, EPA has concluded that the reductions from Utility Units are highly cost-effective, and anticipates that affected states will meet their emission reduction obligations by controlling Utility Unit emissions. EPA also concluded that the technologies that most cost-effectively achieve SO_2 and NO_X reductions for Utility Units are scrubbers for SO_2 and SCR for NO_X. These technologies, as noted above, result in reductions of utility Hg emissions. In conjunction with the CAIR rulemaking, EPA analyzed the nature of Hg emissions that would remain after implementation of the rule and assumed that states would choose to regulate Utility Units, which is the most cost-effective option for achieving the required reductions. That modeling reveals that the implementation of section 110(a)(2)(D), through CAIR, would result in a level of Hg emissions from Utility Units that would not cause hazards to public health. See Section V for further detail. Because this new information demonstrates that the level of Hg emissions projected to remain ''after imposition of'' section 110(a)(2)(D) does not cause hazards to public health, we conclude that it is not appropriate to regulate coal-fired Utility Units under section 112 on the basis of Hg emissions.[30]

In addition to CAIR, we today finalized a rule pursuant to section 111, called the Clean Air Mercury Rule (''CAMR''). (See section VII below for further discussion of CAMR.) That rule requires even greater reductions in Hg emissions from coal-fired Utility Units than CAIR. As explained in greater detail in Section VI, the computer modeling completed in support of that rule, like the modeling completed on CAIR, demonstrates that CAMR, independent of CAIR, will result in levels of utility Hg emissions that do not result in hazards to public health. Thus, the implementation of CAMR provides an independent basis for our conclusion that it is not appropriate to regulate coal-fired Utility Units under section 112 because the utility Hg emissions remaining after implementation of section 111 will be at a level that results in no hazards to public health.[31]

b. It Is Not Necessary to Regulate Coal-fired Units on the Basis of Hg Emissions. Even if Congress had intended EPA to focus on a more limited set of requirements in interpreting the phrase ''after imposition of the requirements of th[e] Act,'' that would mean only that EPA did not err in December 2000 in terms of its ''appropriate'' finding for coal-fired units based on Hg emissions. EPA nevertheless concludes today that it still erred in December 2000 with regard to its ''necessary'' finding. In section 112(n)(1)(A), Congress called on EPA to make a finding as to whether regulation of Utility Units under section 112 was not only ''appropriate,'' but ''necessary.'' To give effect to the term ''necessary,'' we interpret the ''necessary'' prong of the section 112(n)(1)(A) inquiry to require EPA to examine whether there are any other available authorities under the CAA that, if implemented, would effectively address the remaining Hg emissions from coal-fired Utility Units.

[30] The reductions achieved through CAIR overlap, in part, with the 11 tons per year of reductions discussed in the prior section, which EPA estimated in 1998 would occur as the result of implementation of the revised NAAQS. The reductions necessarily overlap because in the Utility Study EPA projected forward 13 years, by examining utility HAP emissions in 2010. In analyzing the level of utility Hg emissions remaining ''after imposition of [section 110(a)(2)(D)]'' through CAIR, we are accounting for the full impact of CAIR and that necessarily includes reductions that occur between today and 2010, and beyond. See Section V (discussing requirements of CAIR in 2010 and 2015).

[31] Nothing in section 112(n)(1)(A) precludes EPA from revising a prior appropriate and necessary finding based on new information. In light of CAIR and, independently, CAMR, we can now reasonably anticipate the reductions in utility Hg emissions that would result from implementation of sections 110(a)(2)(D) and 111 of the CAA. Accordingly, we are accounting for those reductions in assessing the level of utility Hg emissions remaining after ''imposition of the requirements of th[e] Act,'' which include section 110(a)(2)(D) and 111. We then based our new appropriate finding on these remaining Hg emissions.

In December 2000, EPA did not consider CAA sections 110(a)(2)(D) [32] and 111,[33] which are viable alternative authorities under the CAA, that, if implemented, would effectively address the remaining utility Hg emissions. See Section VI below. Regulation under these authorities would effectively address the remaining utility Hg emissions for two primary reasons. First, as demonstrated in section VI below, the level of utility Hg emissions remaining after implementation of CAIR will not result in hazards to public health. Similarly, as shown in section VI below, the CAMR, which requires even greater Hg reductions than CAIR, will, once implemented, result in a level of utility Hg emissions that does not cause hazards to public health.

In addition, controlling Hg emissions through a cap-and-trade system—whether that control is through direct regulation under section 111 or indirect regulation under section 110(a)(2)(D)—is an efficient means of regulating Utility Units. See CAMR final rule (signed on March 15, 2005) (discussing basis and purpose of the regulations). As an initial matter, a cap-and-trade system, as opposed to the control regime imposed pursuant to section 112(d), provides Utility Units the flexibility to pursue a least-cost compliance option to achieve the required emissions reductions.

Sources have the choice of complying with the reductions in a variety of ways, such as fuel switching, installing different pollution control technologies, installing new or emerging control technologies and/or buying allowances to emit from another source that has controlled its emissions to a level below what the regulation requires. This compliance flexibility allows Utility Units to respond to changing electricity generation demands, economic market conditions or unanticipated weather situations (*e.g.*, extremely hot or cold periods) without jeopardizing their compliance status, or the stability of the overall cap. In addition, the certainty provided by the emissions cap and the timeline for declining emissions provide important information for industry to make strategic, long-range business decisions.

Moreover, under a cap-and-trade approach, most of the reductions are projected to result from larger units installing controls and selling excess allowances, due to economies of scale realized on the larger units versus the smaller units. Indeed, EPA's modeling of trading programs demonstrates that large coal-fired Utility Units, which tend to have higher levels of Hg emissions, will achieve the most cost-effective emission reductions. These units are more likely to over-control their emissions and sell allowances, than to not control and purchase allowances. This model prediction is consistent with principles of capital investment in the utility industry. Under a trading system where the firm's access to capital is limited, where the up-front capital costs of control equipment are significant, and where emission-removal effectiveness (measured in percentage of removal) is unrelated to plant size, from an economics standpoint, the utility company is more likely to allocate pollution-prevention capital to its larger facilities than to the smaller plants (since more allowances will be earned from the larger facilities). Economies of scale of pollution control investment will also favor investment at the larger plants. Further, insofar as large coal-fired Utility Units tend to be newer and/or better maintained than medium-sized and small facilities, it can be expected that companies will favor investments in plants with a longer expected lifetime. These modeled predictions are consistent with the pattern of behavior that EPA has observed over the past decade through implementation of the SO_2 emissions trading program under Title IV of the CAA. Thus, under a cap-and-trade program, Hg reductions result from units that are most cost effective to control, which enables those units that are not considered to have cost effective control alternatives to use other mechanisms for compliance, such as buying allowances. By contrast, regulating pursuant to a control regime like section 112(d) does not result in the cost efficiencies that are attendant a cap-and-trade program. For example, under section 112(d), each facility must meet a specific level of emission control, which can result in increased compliance costs, particularly for the smaller Utility Units given economies of scale.

Finally, trading provides greater incentives for the development and adoption of new technologies, which could lead to a greater level of emissions control. See generally 69 FR 4686–87. An additional benefit of the cap-and-trade programs under sections 110(a)(2)(D) and 111 is that they dovetail well with each other. In particular, the coordinated regulation of SO_2, NO_X, and Hg through CAIR and CAMR improves the cost effective manner of regulation because the reductions are being achieved simultaneously using in some cases the same technology to control more than one pollutant. In addition, the cap-and-trade programs under sections 110(a)(2)(D) complement other cap-and-trade programs that directly affect Utility Units, such as the NO_X SIP-call final rule and the regulations implementing Title IV, which only further enhances the efficiencies of emission control from such units.

In light of CAA sections 110(a)(2)(D) and 111, we believe that we should not have concluded in December 2000 that it ''is necessary'' to regulate Utility Units under section 112 and therefore our ''necessary'' finding was in error. Moreover, even setting aside the error that we made in December 2000, we now recognize the availability of these other statutory provisions and we further conclude today that it is not necessary to regulate coal-fired Utility Units under section 112 on the basis of the remaining Hg emissions. CAA section 110(a)(2)(D), as implemented through CAIR, and independently section 111, as implemented through CAMR, will effectively address the Hg emissions remaining from coal-fired Utility Units ''after imposition of the requirements of th[e] Act.''

In sections V and VII below, we address sections 110(a)(2)(D) and 111 and provide a thorough discussion of the legal authority under each provision. We also explain in Section VI that after implementation of CAIR, and independently, CAMR, we do not anticipate hazards to public health resulting from Hg emissions from coal-fired Utility Units.

[32] In January 2004, the proposed section 111 rule was premised, in part, on the reductions in Hg emissions that EPA anticipated would be achieved through CAIR. In response to comments received on the CAMR, we conducted additional modeling that confirmed that CAIR alone, once implemented, would result in levels of utility Hg emissions that do not cause hazards to public health. (See Section VI below). Accordingly, we now believe that CAA section 110()(2)(D) constitutes yet another viable authority under the CAA that, once implemented, will effectively address the remaining utility Hg emissions.

[33] In the Utility Study, we considered section 111 of the CAA, noting that ''new source performance standards currently provide the major regulatory authority for the control of air emissions from utilities.'' Utility Study 1–6. We recognized that we had issued NSPS for PM for Utility Units and we noted that such requirements would result indirectly in the control of certain HAP, including Hg. EPA did not, however, address in the Utility Study the question of whether HAP from utilities could be regulated under the authority of section 111 [Utility Study 1–5–6]. As explained in the proposed rule, we conducted a thorough re-evaluation of the provisions of the CAA and have concluded that section 111 provides authority to regulate HAP from new and existing Utility Units. See Section VII below (discussing legal authority under section 111).

2. It Is Not Appropriate and Necessary to Regulate Coal-Fired Units on the Basis of Non-Hg Emissions

In the study required by section 112(n)(1)(A), and detailed in the Utility Study, EPA identified 67 HAP as potentially being emitted by Utility Units. (Utility Study, ES–4). Based on a screening assessment designed to prioritize HAP for further evaluation, EPA identified 14 HAP as a priority for further evaluation. (Id.). Of the 14 HAP identified for further evaluation, 12 HAP (arsenic, beryllium, cadmium, chromium, manganese, nickel, hydrogen chloride, hydrogen fluoride, acrolein, dioxins, formaldehyde and radionuclides) were identified for further study based on potential for inhalation exposure and risks. (Utility Study, ES–6). Four of those 12 HAP (arsenic, cadmium, dioxins and radionuclides) plus Hg and lead were considered priority for multipathway exposure. (*Id.*). Of those six HAP, four (arsenic, Hg, dioxins and radionuclides) were identified as the highest priority to assess for multipathway exposure and risks. (Utility Study, ES–6, 7). The other 53 HAP were not evaluated beyond the screening assessment. (Utility Study, ES–7).

In evaluating the potential for inhalation exposure and risks for the 12 HAP identified through the screening assessment as priority for that purpose, EPA estimated the high-end inhalation cancer risk for each HAP identified as a carcinogen and the high-end inhalation noncancer risks for the remaining HAP for both coal- and oil-fired Utility Units in 2010. (Utility Study, 6–16, tables 6–8 and 6–9). That evaluation indicated that there was no maximum individual risk (MIR) for cancer greater than 1×10^{-6} for beryllium, cadmium, dioxin and nickel emissions from coal-fired Utility Units and for beryllium, cadmium and dioxin emissions from oil-fired Utility Units. (*Id.*) With regard to dioxins, the Utility Study specifically concluded that the quantitative exposure and risk results did not conclusively demonstrate the existence of health risks of concern associated with inhalation exposures to utility emissions on a national scale or from any actual individual utility. (Utility Study, 11–5). The Utility Study thus indicates that inhalation of beryllium, cadmium and dioxin emissions from coal and oil-fired Utility Units and emissions of nickel from oil-fired Utility Units are not of significant concern from a public health standpoint because such exposure does not present a maximum individual risk (MIR) for cancer greater than 1×10^{-6}. With regard to lead emissions, EPA found that emission quantities and inhalation risks were relatively low and, therefore, decided not to conduct future evaluations of multipathway exposures to lead resulting from Utility Unit emissions. (Utility Study, ES–24). For arsenic, EPA concluded that there were several uncertainties associated with both the cancer risk estimates and the health effects data such that further analyses were needed to characterize the inhalation risks posed by arsenic emissions from Utility Units. (Utility Study, ES–21). The inhalation exposure assessment did not identify any exceedances of the health benchmarks (*e.g.*, RfCs) for hydrogen chloride or hydrogen fluoride, thus indicating that Utility Unit emissions of those HAP did not pose a significant public health concern. (Utility Study chapters 6 and 9.)

a. It Is Not Appropriate to Regulate Coal-fired Units on the Basis of Non-mercury HAP Emissions. The EPA erred in the December 2000 Regulatory Determination to the extent that its ''appropriate'' finding for coal-fired Utility Units was based, in any way, on hazards to public health or the environment arising from emissions of non-mercury HAP from coal-fired Utility Units. Based on the information before it at the time, EPA could not have reasonably concluded that coal-fired Utility Unit non-mercury HAP emissions presented a hazard to public health. In addition, as stated above, EPA should not have considered environmental effects in the December 2000 Regulatory Determination's consideration of whether it was appropriate to regulate HAP emissions from coal-fired Utility Units under section 112.

(i) Non-Mercury Metallic HAP. In the December 2000 Regulatory Determination, EPA indicated that there were a few metallic HAP (*e.g.*, chromium and cadmium) which were of potential concern for carcinogenic effects, but stated that ''the results of the risk assessment (performed in conjunction with the Utility Study) indicate that cancer risks are not high''. (*See* 65 FR 79825, 79827.) The EPA acknowledged, however, that the cancer risks were not low enough to eliminate those metals as a potential concern for public health (*Id.*). This latter statement, at least as it pertains to cadmium, is at odds with the results of the risk assessment set forth in the Utility Study and discussed above. In the Utility Study, EPA determined that there was no maximum individual risk (MIR) for cancer greater than 1×10^{-6} due to inhalation of cadmium emissions from Utility Units. In the Proposed Rule, EPA stated that although it recognized the existence of uncertainties with regard to the data and information obtained prior to the December 2000 Regulatory Determination regarding potential hazards to public health resulting from Utility Unit emissions of non-mercury metallic HAP, the Agency believed that the uncertainties associated with those emissions were so great that it was not appropriate to regulate them at that time because they do not pose a hazard to public health that warrants regulation. (69 FR 4652, 4688, January 30, 2004). The EPA continues to believe that had it properly accounted for the uncertainties regarding the data and information on potential hazards to public health resulting from Utility Unit emissions of non-mercury metallic HAP in making the December 2000 appropriate finding it would have concluded that it was not appropriate to regulate such emissions because they do not cause a hazard to public health. The EPA has not discovered any new information on hazards to public health arising from such emissions that invalidates this conclusion, either through its own efforts or in response to the Proposed Rule.

(ii) Dioxins. In the December 2000 Regulatory Determination, EPA also identified dioxins as being of potential concern and indicated that they may be evaluated further during the regulatory development process. (*See* 65 FR 79825, 79827.) The EPA did not, however, indicate that those concerns rose to a level that warranted regulation of dioxins. Thus, EPA did not conclude, and could not have concluded, based on the record before it at the time of the December 2000 Regulatory Determination that it was appropriate to regulate coal-fired Utility Unit HAP emissions under section 112 of the CAA on the basis of dioxin emissions. In the Proposed Rule EPA stated that while it intended to continue to study dioxins in the future, the Utility Study and the information EPA had obtained since finalizing the Utility Study revealed no public health hazards reasonably anticipated to occur as a result of emissions of dioxins by Utility Units. (*See* 69 FR 4652, 4688). As is the case with non-mercury metallic HAP, EPA has neither discovered information on hazards to public health arising from Utility Unit emissions of dioxins based on its own efforts, nor received such information in response to the Proposed Rule. The EPA therefore concludes that its appropriate finding in December 2000 lacked foundation because it could not have reasonably concluded that the

level of remaining utility dioxin emissions results in hazards to public health.

(iii) Acid Gases. In the December 2000 Regulatory Determination, EPA identified emissions of hydrogen chloride and hydrogen fluoride as being of potential concern and indicated that such emissions may be evaluated further during the regulatory development process. (See 65 FR 79825, 79827.) The EPA did not, however, indicate that it believed that it was appropriate to regulate such emissions, under section 112 or otherwise. As indicated in the Proposed Rule, EPA did in fact further evaluate Utility Unit emissions of hydrogen chloride and hydrogen fluoride. (See 69 FR 4652, 4688, fn. 10; ''Modeling results for hydrogen chloride, hydrogen fluoride and chlorine emissions from coal-fired utility boilers'', December 12, 2003, OAR–2002–0056–0015). That modeling indicates that individuals are not exposed to acid gas emissions from Utility Units at concentrations which pose hazards to public health. EPA has neither discovered information on hazards to public health arising from Utility Unit emissions of acid gases based on its own efforts, nor received such information in response to the Proposed Rule. EPA therefore concludes that its appropriate finding in December 2000 lacked foundation because the level of remaining utility acid gas emissions does not result in hazards to public health.

For the reasons stated above, EPA finds that it could not reasonably have concluded that it was appropriate to regulate coal-fired Utility Units under section 112 due to emissions of non-mercury HAP based on the record before it at the time of the December 2000 Regulatory Determination. The EPA further finds that it has not itself discovered any information which would support the conclusion that it is appropriate to regulate non-mercury HAP emissions by coal-fired Utility Units under section 112 subsequent to the December 2000 Regulatory Determination, nor has it received any such information in response to the January 2004 Proposed Rule, the March 2004 Supplemental Notice or the December 2004 Notice of Data Availability. Further, EPA has concluded that it did not, and should not, rely on potential environmental effects alone in determining whether it was appropriate to regulate coal-fired Utility Units under section 112. The EPA, therefore, finds that, based on the record before it at the time, it was in error in determining that it was appropriate to regulate coal-fired Utility Unit HAP emissions under section 112 to the extent that the determination was based in any way on the hazards to public health of non-mercury HAP emissions or on environmental effects resulting from such emissions.

b. It Is Not Necessary to Regulate Coal-fired Units on the Basis of Non-Mercury HAP Emissions. In determining whether it is appropriate and necessary to regulate Utility Unit HAP emissions under section 112, the threshold question is whether it is appropriate to regulate such emissions at all. Where, as here, EPA cannot reasonably conclude that it is appropriate to regulate such emissions, the Agency does not need to resolve the question of whether it is necessary to regulate such emissions under section 112, or elsewhere. In any event, even if EPA could have reasonably concluded that it was appropriate to regulate non-mercury HAP emissions from coal-fired Utility Units, it would not have been reasonable for the Agency to find that it was necessary to regulate such emissions under section 112 since, as discussed above, it should have realized that there was an available alternative mechanism, such as section 111, for regulating such emissions had it been appropriate to do so. See also Section VII below.

B. Revision of the December 2000 Appropriate and Necessary Finding for Oil-fired Units

1. It Is Not Appropriate and Necessary To Regulate Oil-Fired Units on the Basis of Nickel Emission

a. It Is Not Appropriate to Regulate Oil-fired Units on the Basis of Nickel Emissions. In finding that the regulation of HAP emissions from oil-fired Utility Units was appropriate and necessary in its December 2000 Regulatory Determination, EPA did not clearly identify the basis for this finding beyond stating that there remained uncertainties regarding the extent of the public health impact from HAP emissions from oil-fired units and that those uncertainties led the Administrator to find that regulation of HAP emission from such units under section 112 is appropriate and necessary. (See 65 FR 79825, 79830). Table 1 in the 2000 determination does, however, indicate that nickel is the metallic HAP emitted in the largest quantities by oil-fired Utility Units and that some nickel compounds are carcinogenic. (See 65 FR 79825, 79828). It therefore appears that EPA's finding was based at least in part on its concerns regarding perceived hazards to public health arising from inhalation exposure to nickel emissions from oil-fired Utility Units. This is consistent with the Utility Study which, based on very conservative assumptions regarding the carcinogenicity of the nickel emitted by such units, identifies nickel as the HAP emitted by oil-fired Utility Units which poses the highest cancer maximum individual risk. (Utility Study, Table 6–3, p. 6–8). The Utility Study identifies 11 oil-fired utility plants as having emissions causing maximum individual risk of cancer greater than 10^{-6} based on nickel emissions (*Id.*)

In the Proposed Rule, EPA stated that it continued to believe that the record supports a distinction between the treatment of nickel emissions from oil-fired Utility Units and other non-nickel HAP emissions from such units. EPA proposed to conclude that it was not appropriate to regulate the non-Ni HAP. EPA also proposed to treat nickel from oil-fired units differently based on the amount of nickel emitted annually and the scope of adverse health effects (See 69 FR 4652, 4688). Based on its analysis of new information obtained in response to the Proposed Rule, EPA has determined that the distinction between nickel and the remaining HAP from oil-fired units cannot be supported. EPA finds that it is not appropriate to regulate nickel emissions from oil-fired Utility Units and that it is, therefore, not appropriate to regulate oil-fired Utility Units. This finding is based on the following: (1) The significant reductions in the total nationwide inventory of oil-fired Utility Units; and (2) the changing fuel mixtures being used at the remaining units.

Nickel emissions from oil-fired Utility Units have been substantially reduced since the 1998 Utility Report to Congress through a combination of unit closures and fuel switching. The 11 oil-fired plants identified in the Utility Study as having emissions causing a maximum individual risk of cancer greater than 10^{-6} based on nickel emissions were comprised of 42 individual units. Of those 42 units, 12 units have permanently ceased operation or are out of service. (OAR–2002–0056–2046 at pp. 12–13; OAR–2002–0056–5998). In addition, 6 of the original 42 units have reported to the U.S. Department of Energy (DOE) that their fuel mix now includes natural gas. Earlier reports did not show these units as using natural gas as a fuel. (OAR–2002–0056–5998). The use of natural gas as a part of their fuel mix would decrease the nickel emissions from these 6 units. Similarly, another 5 units report using a mix of natural gas and distillate oil (rather than residual oil) in

2003. (OAR–2002–0056–5998). Since distillate oil contains less nickel than the residual oil previously burned by these units, it is reasonable to assume that these units currently emit less nickel than was previously the case. Another 2 units now fire a residual oil/natural gas mixture and have limited their residual oil use through permit restrictions to no greater than 10 percent of the fuel consumption between April 1 and November 15, with natural gas being used for at least 90 percent of total fuel consumption. (OAR–2002–0056–2046 at p. 13). Finally, five units have effectively eliminated their nickel emissions since the Utility Study by switching to burning natural gas exclusively. (OAR–2002–0056–2046 at pp. 12–13; OAR–2002–0056–5998). Taken as a whole, these changes mean that 30 of the original 42 units identified in the Utility Study have taken steps to reduce or actually eliminate their nickel emissions. Of the original 11 plants identified in the Utility Study, only 2, both in Hawaii, have units for which actions that will result in reduced nickel emissions do not appear to have been taken. (OAR–2002–0056–6871) In addition to the closure of the 12 units identified as being of potential concern in the Utility Study, there has been a steady decrease in the number of oil-fired Utility Units generally over the past decade and this trend is likely to continue. In fact, the latest DOE/EIA projections (OAR–2002–0056–5999) estimate no new utility oil-fired generating capacity and decreasing existing oil-fired generating capacity through 2025, with an additional 29.2 gigawatts of combined oil- and natural gas-fired existing capacity being retired by 2025.

Based on the foregoing, EPA concludes that it is not appropriate to regulate oil-fired Utility Units under section 112 because we do not anticipate that the remaining level of utility nickel emissions will result in hazards to public health.

b. It Is Not Necessary to Regulate Oil-fired Units on the Basis of Nickel Emissions. Because EPA could not have reasonably found that it was appropriate to regulate nickel emissions from oil-fired Utility Units based on the record before it at the time of the December 2000 Regulatory Determination, it should not have made a finding that it was necessary to regulate such emissions. Information obtained in the course of the rulemaking since the Proposed Rule has confirmed this conclusion. In any event, even if EPA could have reasonably concluded that it was appropriate to regulate nickel emissions from oil-fired Utility Units, it would not have been reasonable for the Agency to find that it was necessary to regulate such emissions under section 112 since, as discussed above, it should have realized that there was an available alternative mechanism, section 111, for regulating such emissions had it been appropriate to do so. See also Section VII below.

2. It Is Not Appropriate and Necessary To Regulate Oil-Fired Units on the Basis of Non-Nickel HAP Emissions

a. It Is Not Appropriate to Regulate Oil-fired Units on the Basis of Non-nickel HAP Emissions. As is the case with emissions of nickel, the record before EPA at the time of the December 2000 Regulatory Determination does not reasonably support a finding that it is appropriate to regulate emissions of any other HAP from oil-fired Utility Units. In the December 2000 Regulatory Determination, EPA stated that there remain uncertainties regarding the extent of the public health impact from HAP emissions from oil-fired Utility Units and, on that basis, found that it was appropriate and necessary to regulate oil-fired Utility Units under section 112. (See 65 FR 79825, 79830.) The EPA neither identified the HAP concerning which there were uncertainties nor identified what those uncertainties were. EPA has neither discovered information on hazards to public health arising from the remaining non-nickel emissions of oil-fired Utility Units, nor received such information in response to the Proposed Rule. EPA therefore concludes that its appropriate finding in December 2000 lacked foundation because, given the level of remaining non-nickel HAP emissions from Utility Units, the Agency did not and does not have any information on the hazards to public health reasonably anticipated to occur. Indeed, the uncertainties that exist with regard to the data and information on these emissions are so great that the Agency has not identified any hazards to public health.

b. It Is Not Necessary to Regulate Oil-fired Units on the Basis of Non-nickel HAP Emissions. Because EPA finds that it is not appropriate to regulate oil-fired Utility Units on the basis of non-nickel HAP emissions, it also finds that it is not necessary to regulate oil-fired Utility Units on the basis of such emissions. In any event, even if EPA could have reasonably concluded that it was appropriate to regulate non-nickel HAP emissions from oil-fired Utility Units, it would not have been reasonable for the Agency to find that it was necessary to regulate such emissions under section 112 since, as discussed above, it should have realized that there was an available alternative mechanism, section 111, for regulating such emissions had it been appropriate to do so. See also Section VII below.

V. Statutory and Regulatory Overview of CAA Section 110(a)(2)(D) and Summary of EPA's Clean Air Interstate Rule, Which Implements Section 110(a)(2)(D)

A. The Clean Air Interstate Rule and Clean Air Act Section 110(a)(2)(D)

1. Background for Promulgation of the Clean Air Interstate Rule

The Administrator signed the notice of final rulemaking for the Clean Air Interstate Rule (CAIR) on March 10, 2005. The background for CAIR is fully described in the preambles to the final rule, the notice of proposed rulemaking, 69 FR 4565 (January 30, 2004) and the notice of supplemental rulemaking, 69 FR 12398 (March 16, 2004), and is briefly summarized below.

a. PM 2.5 NAAQS, 8-hour Ozone NAAQS, and the Nonattainment Problems. By notice dated July 18, 1997, we revised the NAAQS for particulate matter to add new standards for fine particles, using as the indicator particles with aerodynamic diameters smaller than a nominal 2.5 micrometers, termed PM 2.5. 62 FR 38652. We established health- and welfare-based (primary and secondary) annual and 24-hour standards for PM 2.5. The annual standard is 15 micrograms per cubic meter, based on the 3-year average of annual mean PM 2.5 concentrations. The 24-hour standard is a level of 65 micrograms per cubic meter, based on the 3-year average of the annual 98th percentile of 24-hour concentrations.

By a separate notice dated July 18, 1997, EPA also promulgated a revised primary NAAQS for ozone (and an identical secondary ozone NAAQS). This revised NAAQS, termed the 8-hour NAAQS, specified that the 3-year average of the fourth highest daily maximum 8-hour average ozone concentration could not exceed 0.08 ppm. (*See* 40 CFR 50.10) In general, the revised 8-hour standard is more protective of public health and the environment and more stringent than the pre-existing 1-hour ozone standard. Following promulgation of the 8-hour ozone and the PM 2.5 NAAQS, EPA anticipated that many areas of the country, particularly in the eastern half of the country, would have air quality violating one or both of those NAAQS.[34]

[34] Environmental Protection Agency, 1996. Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment

b. SO_2 and NO_X as Precursors for PM 2.5 and 8-hour Ozone. Fine particles are emitted directly from emissions sources and also can be formed in the atmosphere through the reaction of gaseous precursors. Sulfur dioxide and nitrogen oxides are among the primary precursors to the ''secondary'' formation of PM 2.5.

Eight-hour ozone is exclusively a secondary pollutant. Ozone is formed by natural processes at high altitudes, in the stratosphere, where it serves as an effective shield against penetration of harmful solar UV–B radiation to the ground. The ozone present at ground level as a principal component of photochemical smog is formed in sunlit conditions through atmospheric reactions of two main classes of precursor compounds: VOCs and NO_X (mainly NO and NO_2). Nitrogen oxides are emitted by motor vehicles, power plants, and other combustion sources, with lesser amounts from natural processes including lightning and soils.

Both PM 2.5 and 8-hour ozone are regional phenomena; that is each is caused by emissions over a broad geographic area. As a result, attainment of the PM 2.5 NAAQS requires reductions in SO_2 and NO_X over a widespread area, and attainment of the 8-hour ozone NAAQS requires reductions in NO_X over a widespread area. In the CAIR proposal, EPA described the photochemistry and need for regionwide reductions of precursors of both pollutants in detail. *See* 69 FR at 4572.

After promulgation of the PM 2.5 NAAQS, EPA was generally aware of the role of SO_2 and NO_X emissions in the PM 2.5 nonattainment problem, and, therefore, of the need for widespread reductions. Similarly, after promulgation of the 8-hour ozone NAAQS, EPA was aware of widespread nonattainment, due to nonattainment of the pre-existing, one-hour ozone standard, and therefore of the need for widespread NO_X reductions.

c. Coal-fired Utility Units Emit A Large Portion of SO_2 and NO_X Emissions. Utility Units emit a large portion of both the SO_2 and NO_X inventory. Congress clearly recognized that the utility industry emits a large portion of the nation's inventory of SO_2 and NO_X emissions when Congress enacted the acid deposition provisions in the 1990 Clean Air Act Amendments. EPA noted in the CAIR proposal that Utility Units—

> are the most significant source of SO_2 emissions and a very substantial source of NO_X in the * * * region [proposed to be affected by CAIR]. For example, EGUs [Utility Units] emissions are projected to represent approximately one-quarter (23 percent) of the total NO_X emissions in 2010 and over two-thirds (67 percent) of the total emissions in 2010 in the 28-State plus DC region that [EPA proposed for] being controlled for both SO_2 and NO_X after application of current CAA controls.

(*See* 69 FR 4565, 4609–10 January 30, 2004.)

Beginning in the mid-1990s, EPA has considered regional and national strategies to reduce interstate transport of SO_2 and NO_X. EPA described these efforts in the CAIR notice of final rulemaking.

3. Legal Authority

As noted above, in 1997, EPA revised the NAAQS for PM to add new annual average and 24-hour standards for fine particles, using PM 2.5 as the indicator (62 FR 38652). At the same time, EPA issued its final action to revise the NAAQS for ozone to establish new 8-hour standards (62 FR 38856.) Following promulgation of new NAAQS, the CAA requires all areas, regardless of their designation as attainment, nonattainment, or unclassifiable, to submit SIPs containing provisions specified under section 110(a)(2). SIPs for nonattainment areas are generally required to include additional emissions controls providing for attainment of the NAAQS. In addition, under the authority of section 110(a)(2)(D) and other provisions of section 110, EPA promulgated the NO_X SIP-Call in 1998. In that rulemaking, EPA determined that 22 States and the District of Columbia in the eastern half of the country significantly contribute to 1-hour and 8-hour ozone nonattainment problems in downwind States.[35] This rule required those jurisdictions to revise their SIPs to include NO_X control measures to mitigate the significant ozone transport. The EPA determined the emissions reductions requirements by projecting NO_X emissions to 2007 for all source categories and then reducing those emissions through controls that EPA determined to be highly cost-effective. The affected States were required to submit SIPs providing the resulting amounts of emissions reductions.

Under the NO_X SIP-Call, States had the flexibility to determine the mix of controls to meet their emissions reductions requirements. However, the rule provided that if the SIP controls Utility Units, then the SIP must establish a budget, or cap, for Utility Units. The EPA recommended that each State authorize a trading program for NO_X emissions from Utility Units. We developed a model cap and trade program that States could voluntarily choose to adopt, and all did so.

4. CAIR

In CAIR, EPA established SIP requirements for the affected upwind States under the authority of CAA section 110(a)(2)(D) and other provisions of section 110.[36] Based on air quality modeling analyses and cost analyses, EPA concluded that SO_2 and NO_X emissions in certain States in the eastern part of the country, through the phenomenon of air pollution transport, contribute significantly to downwind nonattainment of the PM 2.5 and 8-hour ozone NAAQS. In CAIR, EPA required SIP revisions in 28 States and the District of Columbia to reduce SO_2 and/or NO_X emissions, which are important precursors of PM 2.5 (NO_X and SO_2) and ozone (NO_X). The affected States and the District of Columbia are required to adopt and submit the required SIP revision with the necessary control measures by 18 months from date of signature of CAIR.

The 23 States along with the District of Columbia that must reduce annual NO_X emissions for the purposes of the PM 2.5 NAAQS are: Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

The 25 States along with the District of Columbia that must reduce NO_X emissions for the purposes of the 8-hour ozone NAAQS are: Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina,

of Scientific and Technical Information. OAQPS Staff Paper. Research Triangle Park, NC: Office of Air Quality Planning and Standards; Report No. EPA–45/R–96–013.

[35] *See* ''Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Final Rule,'' 63 FR 57356 (October 27, 1998). The EPA also published two Technical Amendments revising the NO_X SIP Call emission reduction requirements. (64 FR 26298; May 14, 1999 and 65 FR 11222; March 2, 2000).

[36] *See* ''Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule); Proposed Rule,'' 69 FR 4566 (January 30, 2004); ''Supplemental Proposal for the Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Proposed Rule,'' 69 FR 32684 (June 10, 2004); and the final rule ''Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule),'' which was recently issued.

Tennessee, Virginia, West Virginia, and Wisconsin.

The emissions reductions requirements are based on controls that EPA determined to be highly cost-effective for Utility Units. However, States have the flexibility to choose the measures to adopt to achieve the specified emissions reductions. If the State chooses to control Utility Units, then it must establish a budget—that is, an emissions cap—for those sources. CAIR defines the Utility Units budgets for each affected State. Due to feasibility constraints, EPA is requiring that emissions reductions be implemented in two phases, with the first phase in 2009 (for NO_X) and 2010 (for SO_2), and the second phase in 2015.

As noted above, under the CAIR, each State may independently determine which emissions sources to subject to controls, and which control measures to adopt. The EPA's analysis indicates that emissions reductions from Utility Units are highly cost-effective, and in the CAIR, EPA encouraged States to adopt controls for Utility Units. States that do so must place an enforceable limit, or cap, on Utility Unit's emissions. The EPA calculated the amount of each State's Utility Unit emissions cap, or budget, based on reductions that EPA determined are highly cost-effective. States may allow their Utility Units to participate in an EPA-administered cap-and-trade program as a way to reduce the cost of compliance, and to provide compliance flexibility. The EPA will administer these programs, which will be governed by rules provided by EPA that States may adopt or incorporate by reference.

EPA estimated that the CAIR would reduce annual SO_2 emissions by 3.6 million tons by 2010 and by 4.0 million tons by 2015; and would reduce annual NO_X emissions by 1.3 million tons by 2010 and by 1.5 million tons by 2015. If all the affected States choose to achieve these reductions through Utility Unit controls, then Utility Unit emissions in the affected States would be capped at 3.7 million tons in 2010 and 2.6 million tons in 2015; and Utility Unit annual NO_X emissions would be capped at 1.5 million tons in 2010 and 1.3 million tons in 2015. The EPA estimated that the required SO_2 and NO_X emissions reductions would, by themselves, bring into attainment 52 of the 80 counties that are otherwise expected to be in nonattainment for PM 2.5 in 2010, and 57 of the 75 counties that are otherwise expected to be in nonattainment for PM 2.5 in 2015. The EPA further estimated that the required NO_X emissions reductions would, by themselves, bring into attainment 3 of the 40 counties that are otherwise expected to be in nonattainment for 8-hour ozone in 2010, and 6 of the 22 counties that are expected to be in nonattainment for 8-hour ozone in 2015. In addition, the CAIR would improve PM 2.5 and 8-hour ozone air quality in the areas that would remain nonattainment for those two NAAQS after implementation of CAIR. Because of the CAIR, the States with those remaining nonattainment areas will find it less burdensome and less expensive to reach attainment by adopting additional local controls. The CAIR would also reduce PM 2.5 and 8-hour ozone levels in attainment areas.

C. Utility Mercury Emission Reductions Expected as Co-Benefits From CAIR

The final CAIR requires annual SO_2 and NO_X reductions in 23 States and the District of Columbia, and also requires ozone season NO_X reductions in 25 States and the District of Columbia. Many of the CAIR States are affected by both the annual SO_2 and NO_X reduction requirements and the ozone season NO_X requirements. CAIR was designed to achieve significant emissions reductions in a highly cost-effective manner to reduce the transport of fine particles that have been found to contribute to nonattainment. EPA analysis has found that the most efficient method to achieve the emissions reduction targets is through a cap-and-trade system on the power sector that States have the option of adopting. In fact, States may choose not to participate in the optional cap-and-trade program and may choose to obtain equivalent emissions reductions from other sectors. However, EPA believes that a region-wide cap-and-trade system for the power sector is the best approach for reducing emissions. The power sector accounted for 67 percent of nationwide SO_2 emissions and 22 percent of nationwide NO_X emissions in 2002.

EPA expects that States will choose to implement the final CAIR program in much the same way they chose to implement their requirements under the NO_X SIP Call. As noted above, under the NO_X SIP Call, EPA gave States ozone season NO_X reduction requirements and the option of participating in a cap-and-trade program. In the final rulemaking, EPA analysis indicated that the most efficient method to achieve reductions targets would be through a cap-and-trade program. Each affected State, in its approved SIP, chose to control emissions from Utility Units and to participate in the cap-and-trade program.

Therefore, EPA anticipates that States will comply with CAIR by controlling Utility Unit SO_2 and NO_X emissions. Further, EPA anticipates that States will implement those reductions through the cap-and-trade approach, since the power sector represents the majority of national SO_2 emissions and the majority of stationary NO_X emissions, and represent highly cost-effective SO_2 and NO_X sources to reduce. For further discussion of cost-effectiveness, see section IV of CAIR notice of final rulemaking. EPA modeled a region-wide cap and trade system on the power sector for the States covered by CAIR, and this modeling projected that most reductions in NO_X and SO_2 would come through the installation of scrubbers, for SO_2 control, and selective catalytic reduction for NO_X control (see Regulatory Impact Assessment for CAIR and CAMR in docket). Scrubbers and SCR are proven technologies for controlling SO_2 and NO_X emissions and sources installed them to comply with the Acid Rain trading program and the NO_X SIP Call trading program. EPA's modeling also projected that the installation of these controls would achieve Hg emission reductions as a co-benefit.

EPA projections of Hg co-benefits are based on 1999 Hg ICR emission test data and other more recent testing conducted by EPA, DOE, and industry participants. (For further discussion see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005, in the docket). That emission testing has provided a better understanding of Hg emissions and their capture in pollution control devices. Mercury speciates into three basic forms, ionic, elemental, and particulate (particulate represents a small portion of total emissions). In general, ionic Hg compounds are more readily absorbed than elemental Hg and the presence of chlorine compounds (which tend to be higher for bituminous coals) results in increased ionic Hg. Overall the 1999 Hg ICR data revealed higher levels of Hg capture for bituminous coal-fired plants as compared to subbituminous and lignite coal-fired plants and a significant capture of ionic Hg in wet SO_2 scrubbers. Additional Hg testing indicates that for bituminous coals SCR has the ability to convert elemental Hg to ionic Hg and thus allow easier capture in a wet scrubber. This understanding of Hg capture was incorporated into EPA modeling assumptions and is the basis for our projections of Hg co-benefits from installation of scrubbers and SCR under CAIR.

The final CAIR requires annual SO_2 and NO_X reductions in two phases, the

first phase in 2010 and the second phase in 2015. EPA modeling of CAIR projected that most reductions in NO_X and SO_2 would come through the installation of scrubbers and SCR, and that the installation of these controls would also achieve Hg emission reductions as a co-benefit. Given the history of the Acid Rain and NO_X SIP Call trading programs, and our experience with those programs, we anticipate that reductions in SO_2 emissions will begin to occur before 2010 because of the ability to bank SO_2 emission allowances, though to some degree this is limited by the time and resources needed to install control technologies. Companies have an incentive to achieve greater SO_2 reductions than needed to meet the current Acid Rain cap because the excess allowances they generate can be ''banked'' and either later sold on the market or used to demonstrate compliance in 2010 and beyond at the facility that generated the excess allowances. Based on the analysis of CAIR, EPA's modeling projects that Hg emissions would be 38.0 tons (12 tons of non-elemental Hg) in 2010, 34.4 tons in 2015 (10 tons of non-elemental Hg), and 34.0 tons in 2020 (9 tons of non-elemental Hg), about a 20 and 30 percent reduction (in 2010 and 2015, respectively) from a 1999 baseline of 48 tons.[37] For further discussion of EPA modeling results and projected emissions see Chapter 8 of the Regulatory Impact Assessment.[38]

[37] As discussed in the TSD, the emissions of reactive gaseous Hg and particle-bound Hg are most important for local and regional Hg deposition purposes, since they are substantially more likely to be deposited than elemental Hg. CAIR and CAMR will significantly reduce reactive gaseous Hg and particle bound Hg from 2001 levels. CAIR will reduce the levels from approximately 22 tons to 9 tons. CAMR will reduce this level further to between 7 and 9 tons, for a total reduction (with CAIR) of roughly 70 percent.

[38] In addition to CAIR, EPA recently promulgated another rule for Utility Units. Specifically, on March 15, 2005, the Administrator signed a final rulemaking called the Clean Air Mercury Rule (''CAMR'') pursuant to CAA section 111. This rule sets standards of performance for Hg emitted from both new and existing coal-fired Utility Units. Like CAIR, the rule establishes a cap-and-trade mechanism by which Hg emissions from new and existing coal-fired Utility Units are capped at specified, nation-wide levels. The first phase cap of 38 tons per year (''tpy'') becomes effective in 2010 and the second phase cap of 15 tpy becomes effective in 2018. Facilities must demonstrate compliance with the standards of performance by holding one ''allowance'' for each ounce (oz) of Hg emitted in any given year. Allowances are readily transferrable among all regulated units. As explained in section VI below, the level of Hg emissions remaining after implementation of CAMR do not result in hazards to public health.

VI. Scientific and Technical Background and EPA'S Conclusions Concerning the Level of Utility Attributable Mercury Emissions After CAIR and CAMR

In this section, we explain why we believe the level of utility attributable Hg emissions remaining after imposition of CAIR, and independently, CAMR, will not result in hazards to public health. The issue of whether utility Hg emissions remaining after CAIR, and independently CAMR, result in hazards to public health is directly related to our conclusion, stated above in Section IV.A, that we cannot find it appropriate and necessary to regulate coal-fired Utility Units under section 112 on the basis of Hg emissions. This section includes an overview of the scientific and technical information relevant to evaluating utility Hg emissions and the public health impacts associated with such emissions. Below, we provide general background concerning the health impacts of methylmercury; the predominant exposure pathway by which humans are affected by methylmercury, which is by ingestion of fish containing methylmercury; and EPA's methodology for determining the impacts of utility Hg emissions on the amount of methylmercury found in fish tissue. This section also includes a summary of our conclusions, including that utility Hg emissions remaining after implementation of CAIR, and independently CAMR, are not reasonably anticipated to result in hazards to public health.

A. Human Health Impacts of Methylmercury Exposure and Amounts of Hg Emissions

Hg is a persistent, bioaccumulative toxic metal that is emitted from power plants in three forms: Elemental mercury (Hg\0\), oxidized mercury (Hg\++\) compounds, as well as particle-bound mercury. Methylmercury is formed by microbial action in the top layers of sediment and soils, after Hg has precipitated from the air and deposited into water bodies or land. Once formed, methylmercury is taken up by aquatic organisms and bioaccumulates up the aquatic food web. Larger predatory fish may have methylmercury concentrations many times that of the water body in which they live.

While Hg is toxic to humans when it is inhaled or ingested, we focus on oral exposure of methylmercury in this rulemaking, as it is the route of primary interest for human exposures in the U.S. Methylmercury is a well-established human neurotoxicant. Methylmercury that is ingested by humans is readily absorbed from the gastrointestinal tract and can cause effects in several organ systems. The best studied effect of low level exposure is the ability of methylmercury to cause subtle, yet potentially important neurodevelopmental effects. Of particular concern is the effect of methylmercury on the developing fetal nervous system exposed in utero from maternal fish ingestion. Large prospective epidemiological studies have reported that prenatal methylmercury from environmental exposures has been associated with poor performance on neurobehavioral tests in children. These include tests that measure attention, visual-spatial ability, verbal memory, language skills, and fine motor function. These studies have been thoroughly reviewed, singly and as part of review groups, by many expert scientists, including a panel of the National Research Council (NRC) of the National Academy of Sciences (NAS).[39] While important, the weight of evidence for cardiovascular effects is not as strong as it is for childhood neurological effects and the state of the science is still being evaluated. However, some recent epidemiological studies in men suggest that methylmercury is associated with a higher risk of acute myocardial infaraction, coronary heart disease and cardiovascular disease in some populations. Other recent studies have not observed this association. The findings to date and the plausible biological mechanisms warrant additional research in this area (Stern 2005; Chan and Egeland 2004). There is some recent evidence that methylmercury may result in genotoxic or immunotoxic effects. Overall, there is a relatively small body of evidence from human studies that suggests exposure to methylmercury can result in immunotoxic effects and the NRC concluded that evidence that human exposure caused genetic damage is inconclusive. There are insufficient human data to evaluate whether these effects are consistent with levels in the U.S. population. Because the developing fetus may be the most sensitive to the effects from methylmercury, women of

[39] Studies investigating the relationship between methylmercury and cardiovascular effects have reached different conclusions. Some recent epidemiological studies of men suggest that methylmercury is associated with a higher risk of acute myocardial infarction, coronary heart disease and cardiovascular disease in some populations. Other research with less corroboration suggest that reproductive, renal, and hematological impacts may be of concern. There are insufficient human data to evalaute whether these effects are consistent with levels in the U.S. population. *See* RIA for CAMR chapter 2.

child-bearing age are regarded as the population of greatest interest when assessing methylmercury exposure.

The predominant pathway of Hg exposure to both humans and wildlife is consumption of fish. Critical elements in estimating methylmercury exposure and risk from fish consumption include the concentrations of methylmercury in the fish consumed, the quantity of fish consumed,[40] and how frequently the fish is consumed. There is a great deal of variability among individuals in fish consumption rates. However, our analysis indicates that the typical U.S. consumer eating moderate amounts of a wide variety of low-mercury fish from restaurants and grocery stores is not expected to ingest harmful levels of methylmercury from fish. Those who regularly and frequently consume large amounts of fish, or fish with higher levels of methylmercury, are more exposed. The EPA and Food and Drug Administration jointly, as well as states, have issued fish consumption advisories to inform people of ways to reduce exposure to methylmercury from fish.

As part of its long term U.S. population surveillance, the U.S. Centers for Disease Control (CDC) assessed Hg concentrations in blood of over 3,600 women of child-bearing age under the National Health and Nutrition Examination Survey (NHANES). A recent analysis of these data reported that about 6 percent of these women of child-bearing age have levels of Hg in their blood that are at or above the U.S. EPA's RfD, described below. The CDC also surveyed the same group of women about their eating habits. An analysis of 1500 of these women showed that Hg blood levels were higher in the women who reported eating three or more servings of fish in the month before they were tested. It is reasonable to conclude that methylmercury contained in seafood may be responsible for elevated levels of Hg in U.S. women of child-bearing age.[41]

As described below, the analysis supporting today's action focuses on assessing exposure from freshwater fish caught and consumed by recreational and subsistence anglers because available information indicate that U.S. utility Hg emissions may affect the methylmercury concentrations in these fish. EPA also considered the following fish consumption pathways: Consumption from commercial sources (including saltwater and freshwater fish from domestic and foreign producers); consumption of recreationally caught marine fish, consumption of recreationally caught estuarine fish; and consumption of commercial fish raised at fish farms (aquaculture). For a number of reasons, as explained in the TSD, current information does not suggest that these latter pathways present meaningful risks of ingestion of utility-attributable methylmercury.

The EPA's 1997 Mercury Study Report to Congress suggests a plausible link between anthropogenic releases of Hg from industrial and combustion sources in the U.S. and methylmercury in fish in the U.S. However, other sources of Hg emissions, including Hg from natural sources (such as volcanos) and anthropogenic emissions in other countries, contribute to the levels of methylmercury observed in fish in the U.S.[42] Our current understanding of the global Hg cycle and the impact of the anthropogenic sources allow us to make estimates on a global, continental, or regional scale of their relative importance. It is more difficult to make accurate predictions of the fluxes on a local scale given our current understanding.

We recognize that it is also difficult to quantify with precision how a specific change in air deposition of Hg leads to a change in fish tissue levels. We further recognize that the relationship between the amount of Hg emissions reduced and the attendant reduction in methlymercury fish concentrations depends upon the specific characteristics of the waterbody at issue. Nevertheless, science continues to evolve and EPA has made substantial progress in developing methods for assessing the amount of methylmercury in fish tissues that may be traced to emissions from coal-fired U.S. Utility Units. We describe our methodology below and why this methodology is sufficient to support today's action.

As discussed above, we are focusing on consumption of self-caught, freshwater fish. We estimate that there are approximately 27.9 million recreational freshwater fishers in the U.S. population, including fishers who do not eat (*e.g.,* release) their catch. Based on application of a ''consuming'' factor and a ''sharing'' factor to the estimate of recreational fishers, as discussed further in the RIA to CAMR, we estimate that approximately 58.6 million individuals in the U.S. population consume recreationally-caught freshwater fish. Of these individuals, we estimate that approximately 7.5 to 10.5 million are women of child-bearing age (that is, 15–44 years old), about 500,000 of whom are expected to give birth in any one year. We estimate that the mean recreational freshwater fish consumption rate for these women is 8 grams/day, and the 95th percentile recreational freshwater fish consumption rate is 25 grams/day. A subset of recreational freshwater fish consumers may consume at higher levels, as discussed below. In addition, subsistence fishers and fishers in certain ethnic groups are expected to have generally higher fish consumption rates than consumers of recreational freshwater fish. These sub-populations are discussed below.

B. The Methylmercury Reference Dose

EPA generally quantifies risk of adverse health effects other than cancer by calculating a reference value (RfV). In general, an RfV is an estimation of an exposure that is likely to be without an appreciable risk of adverse effects over a lifetime. See *http://www.epa.gov/iris/gloss8.htm.* RfVs for exposure by ingestion are called reference doses (RfD).

The EPA defines an RfD as ''an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily oral exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. It can be derived from a NOAEL (no observed adverse effect level), LOAEL (lowest observed adverse effect level), or benchmark dose, with uncertainty factors generally applied to reflect limitations of the data used.'' *See http://www.epa.gov/iris/gloss8.htm.*

As stated above, an RfD is derived by choosing a point of departure from animal or human data. This can be a NOAEL or LOAEL, either of which may be defined by applying statistical tests and scientific judgment to the data. When the data are sufficient, one can apply a mathematical model to obtain a benchmark dose (BMD). The BMD is the dose at which a particular level of response (*i.e.*, the benchmark response,

[40] A precise estimate of methylmercury exposure depends on quantity of fish consumed as a function of an individual's body weight.

[41] 289 JAMA 1667 (April 2, 2003).

[42] Recent Hg estimates (which are highly uncertain) of annual total global emissions from all sources (natural and anthropogenic) are about 5,000 to 5,500 tons per year (tpy). Of this total, about 1,000 tpy are estimated to be natural emissions and about 2,000 tpy are estimated to be contributions through the natural global cycle of re-emissions of Hg associated with past natural releases and anthropogenic activity. Current anthropogenic emissions account for the remaining 2,000 tpy. Given the global estimates noted above, U.S. anthropogenic Hg emissions are estimated to account for roughly 3 percent of the global total, and U.S. utilities are estimated to account for about 1 percent of total global emissions. Deposition from U.S. utilities is described in greater detail below. Utility RTC at 7–1 to 7–2; Mercury NPR, 69 FR 4657–58 (January 20, 2004); RIA for CAMR chapters 5–6.

or BMR) for some outcome of concern is found to occur. One can then derive a BMD lower confidence limit (BMDL), which is a statistical lower bound on the chosen BMD, an exposure expected to produce a specified effect in some defined percentage of a test population.

The point of departure (again, NOAEL, LOAEL, or BMDL) is divided by uncertainty/variability factors to arrive at the RfD. The uncertainty factors are intended to account for variability and uncertainty in the data. The size of an uncertainty/variability factor is determined by the adequacy or limitations of the data and is typically either 10 or 3 for each type of variabilty. For example, uncertainty factors may be employed for extrapolating from animals to humans, variability in human susceptibility (sensitive populations), and extrapolating from subchronic to chronic exposures. The resulting RfD is believed to be the amount of a chemical which, when ingested daily over a lifetime, is likely to be without an appreciable risk of deleterious effects to humans, including sensitive subpopulations.

In 2001, EPA published an RfD for methylmercury that is based on a BMD approach. This quantitative risk estimate was based on data from developmental neurotoxicity studies mentioned above; specifically, deficits in tests associated with ability to learn and process information. EPA applied an uncertainty/variability factor of 10 to the point of departure (BMDL) to derive the RfD. EPA's RfD for methylmercury is 0.1 µg/kg bw/day, which is 0.1 micrograms of Hg per day for each kilogram of a person's body weight.

As noted in the Hg Proposal, at the direction of Congress, EPA funded the NAS to perform an independent evaluation of the available data related to the health impacts of methylmercury and provide recommendations for EPA's RfD. The NAS/National Research Council (NRC) conducted an 18-month study of the available data on the health effects of methylmercury. The review by the NAS, published in July 2000, concluded that the neuro-developmental effects are the most sensitive and well-documented effects of methylmercury exposure. The NRC advised revising the basis of the RfD, which used data from a short-term exposure in Iraq, to incorporate new studies on children exposed in utero when their mothers ate seafood containing Hg. EPA subsequently established a reference dose of 0.0001 mg/kg bw/day. NAS determined that EPA's RfD ''is a scientifically justified level for the protection of public health.''

The methylmercury RfD is further described in the RIA, chapter 2 and in other EPA documents (IRIS, U.S. EPA 2001; Water Quality Criteria for the Protection of Human Health: Methylmercury, EPA–823–R–01–001). Briefly, EPA used as the point of departure BMDLs for multiple endpoints from the three studies of in utero methylmercury exposure and effects. These were conducted in the Faroes and Seychelles Islands and in New Zealand.[43] All of the endpoints were children's scores on neuropsychological tests. Consistent with NRC recommendations, an uncertainty/variability factor of 10 was used to account for pharmacokinetic and pharmacodynamic variability in the human population. In the EPA documents, one data set from the Faroes (Boston Naming Test, full cohort) is displayed for all calculations as an example of the multiple BMDLs which serve as the basis for the RfD.

In determining the RfD for methylmercury, EPA said that the ''RfD can be considered a threshold for a population at which it is unlikely that adverse effects will be observed'' (Water Quality Criteria for the Protection of Human Health: Methylmercury, EPA–823–R–01–001). The RfD was calculated to be a level ''likely to be without an appreciable risk,'' of ''deleterious effects'' for all populations, including sensitive subgroups. EPA does not further quantify the degree of risk which would be expected for exposures at or above the methylmercury RfD. This is the case for all of EPA's RfDs. Additional regulatory values support a similar threshold approach for describing risks to methylmercury exposure. For example, the World Health Organization sets the level at 0.23 µg/kg/day; Health Canada sets the level at 0.2 µg/kg/day; and the Agency for Toxic Substances and Disease Registry (ATSDR) sets a value of 0.3 µg/kg/day.

EPA has established the RfD at a level such that exposures at or below the RfD are unlikely to be associated with appreciable risk of deleterious effects. It is important to note, however, that the RfD does not define an exposure level corresponding to zero risk; exposure near or below the RfD could pose a very low level of risk which EPA deems to be non-appreciable. It is also important to note that the RfD does not define a bright line, above which individuals are at risk of adverse effects.

Further, in EPA's 1989 Residual Risk Report to Congress, we stated:

> It should be noted that exposures above an RfD or RfC do not necessarily imply unacceptable risk or that adverse health effects are expected. Because of the inherent conservatism of the RfC/RfD methodology, the significance of exceedances must be evaluated on a case-by-case basis, considering such factors as the confidence level of the assessment, the size of UF used, the slope of the dose-response curve, the magnitude of the exceedance, and the number or types of people exposed at various levels above the RfD or RfC.[44]

[43] More specifically, the subjects of the Seychelles longitudinal prospective study were 779 mother-infant pairs from a fish-eating population (Myers *et al.*, 1995a–c, 1997; Davidson *et al.*, 1995, 1998). Infants were followed from birth to 5.5 years of age, and assessed at various ages on a number of standardized neuropsychological endpoints. The independent variable was maternal-hair Hg levels. The Faroe Islands study was a longitudinal study of about 900 mother-infant pairs (Grandjean *et al.*, 1997). The main independent variable was cord-blood Hg; maternal-hair Hg was also measured. At 7 years of age, children were tested on a variety of tasks designed to assess function in specific behavioral domains. The New Zealand study was a prospective study in which 38 children of mothers with hair Hg levels during pregnancy greater than 6 ppm were matched with children whose mothers had lower hair Hg levels (Kjellstrom *et al.*, 1989, 1986). At 6 years of age, a total of 237 children were assessed on a number of neuropsychological endpoints similar to those used in the Seychelles study (Kjellstrom *et al.*, 1989). The Seychelles study yielded no statistically significant evidence of impairment related to in utero methylmercury exposure, whereas the other two studies found dose-related effects on a number of neuropsychological endpoints. In the assessment described here, an integrative analysis of all three studies was relied upon in setting the point of departure for derivation of the RfD. As noted by NRC in reference to data from the Seychelles, Faroe Islands, and New Zealand, ''because those data are epidemiological, and exposure is measured on a continuous scale, there is no generally accepted procedure for determining a dose at which no adverse effects occur.'' (NRC 2000)

[44] U.S. Environmental Protection Agency. 1989. Risk Assessment Guidance for Superfund: Volume I. Human Health Evaluation Manual (Part A). Office of Emergency and Remedial Response. Washington, DC, EPA/541/1–89/002, at 52–53 *http://www.epa.gov/oswer/riskassessment/ragsa/pdf/ch8.pdf* (Residual Risk Report). The Residual Risk Report further stated:

> It is expected that an HI (*i.e.*, hazard index (HI)), which is the sum of more than one hazard quotient for multiple substances and/or multiple exposure pathways) less than 1 that is derived using target organ specific hazard quotients would ordinarily be considered acceptable. If the HI is greater than 1, then the amount by which the HI is greater than 1, the uncertainty in the HI, the slope of the dose-response curve, and a consideration of the number of people exposed would be considered in determining whether the risk is acceptable. Evaluation of the acceptable value for an HQ (*i.e.*, hazard quotient (HQ), which is the ratio of the exposure level to a reference exposure level (*e.g.*, RfD)) or an HI of 1 also would consider the values of UFs (*i.e.*, uncertainty/variability factor (UF)), which is a default factor—generally 10-fold—used in operationally deriving the RfD or RfC from experimental data) and the confidence in the RfC that are used in the calculation of the HI. In general, it is considered that each UF is somewhat conservative; because all factors are not likely to simultaneously be at their most extreme (highest) value, a combination of several factors can lead to substantial conservatism in the final value. Larger

Continued

C. Methylmercury Levels in Fish and the Methylmercury Water Quality Criterion

As noted above, the most important pathway of exposure to Hg for humans is through the consumption of fish and seafood. These include saltwater fish such as tile fish, shark, and swordfish, which are most often caught commercially. They also include freshwater fish such as bass, perch, and walleye, which are often caught recreationally, commercially, or for personal consumption or distribution. Generally shellfish have lower levels of methylmercury than do finfish. The levels of Hg in fish and shellfish are variable, with mean levels ranging from non-detectable to 1.45 mg/kg, depending on species. See FDA Mercury Levels in Commercial Fish and Shellfish (*http://www.cfsan.fda.gov/~frf/sea-mehg.html*).

Methylmercury exposure is a function of how much fish is eaten (on a bodyweight basis), how frequently fish is eaten, and the methylmercury concentration in the fish. As a result, estimates of the amount and type of fish consumption are important to assessing the impacts of methylmercury attributed to coal-fired Utility Units on public health.

Hg is emitted from powerplants in three forms: Elemental Hg, reactive (oxidized) Hg, and particulate Hg. Most of the local and regional Hg deposition is associated with the emissions of reactive Hg. For this reason, the magnitude of reactive Hg emission from powerplants is critical to Hg deposition in the United States. As noted above, FGD and SCR control technologies are most effective in controlling reactive Hg emissions. As indicated by Table VI–2, roughly 90 percent of the Hg reductions under CAIR in 2020 are reactive Hg. As a result, the SO_2 and NO_X limits established by CAIR yield significant reductions (roughly 70 percent) in reactive Hg emissions from powerplants.

Americans eat fish from a variety of sources. An individual's fish diet can be composed of commercial fish and shellfish (both imported and domestic), fish from aquaculture (or farm raised fish for commercial sale), and fish from non-commercial sources (*e.g.*, recreationally caught fish, fish caught to meet dietary needs, and/or fish caught for cultural or traditional reasons). These fish may come from marine, estuarine, or freshwater sources.

Using the 2001 RfD and information on Hg exposure routes, EPA published a recommended ambient water quality criterion for the states' and tribes' use in setting water quality standards for U.S. waters (freshwater and estuarine) that are designed to protect human health. EPA issued the methylmercury water quality criterion in 2001. Water Quality Criterion for the Protection of Human Health: Methylmercury. EPA–823–R–01–001. Office of Science and Technology, Office of Water, USEPA, Washington, DC, USEPA 2001) Because of the wide variability in methylmercury bioaccumulation among waterbodies, EPA set the criterion as a fish tissue level rather than as an ambient water concentration. The criterion is 0.3 mg/kg (milligram methylmercury per kilogram of wet-weight fish tissue). The criterion is a risk assessment number that states and authorized tribes may use in their programs for protection of designated uses.

The Clean Water Act (CWA) and EPA's regulations specify requirements for adoption of water quality criteria. States and authorized tribes must adopt water quality criteria that protect designated uses. See CWA section 303(c)(2)(A). Water quality criteria must be based on a sound scientific rationale and must contain sufficient parameters or components to protect the designated uses. See 40 CFR 131.11. States and authorized tribes must adopt criteria for all toxic pollutants where EPA has established ambient water quality criteria where the discharge or presence of these pollutants could reasonably interfere with the designated uses. See CWA Section 303(c)(2)(B). EPA issued guidance on how states and authorized tribes may comply with section 303(c)(2)(B) which is now contained in the *Water Quality Standards Handbook: Second Edition* (EPA, 1994). States and authorized tribes that decide to use the recommended methylmercury criterion as the basis for new or revised methylmercury water quality standards have the option of adopting the criterion as a fish tissue concentration into their water quality standards, adjusting the criterion to account for state or local exposure, or adopting it as a traditional water column concentration. States and authorized tribes remain free not to use EPA's current recommendations, provided that their new or revised water quality criteria for methylmercury protect the designated uses and are based on a scientifically defensible methodology.

The methylmercury water quality criterion incorporated the RfD, data on freshwater and estuarine finfish and shellfish consumption for the target population (the adult general population), and information on exposure to methylmercury as a result of consumption of marine fish (for methylmercury, exposure from any route other than eating fish is negligible). Specifically, EPA assumed a default intake of freshwater and estuarine and marine finfish and shellfish of 17.5 grams per day (or two 8-ounce meals a month) conforming to EPA's methodology. (EPA; ''Methodology for Deriving Ambient Water Quality Criteria for the Protection of Human Health (2000),'' EPA–822–B–00–004 (October 2000) (''2000 Water Quality Criteria Methodology'')). This default (to be used by EPA for national criteria or others in the absence of data specific to a waterbody) is the 90th percentile total (commercial and non-commercial) freshwater and estuarine finfish and shellfish consumption reported by adults, both consumers and non-consumers. The source of this data is the 1994–1996 Continuing Study of Food Intake by Individuals (CSFII). This is a large ongoing U.S. food consumption survey conducted by USDA.

In addition, in accordance with EPA's published methodology, in developing the criterion, EPA used a relative source contribution (RSC) approach to apportion the RfD to ensure that the water quality criterion is protective, given other sources of exposure. The RSC approach apportions the RfD according to routes of exposures; for methylmercury this adjustment was done to account for marine fish consumption, as the criterion is for freshwater and estuarine finfish and shellfish. In deriving the methylmercury water quality criterion, EPA assumed an exposure to methylmercury in marine fish that is equivalent to 27 percent of RfD. That is, EPA developed the criterion so that it would be protective even if an individual is consuming typical amounts of fish from other sources (*i.e.*, marine fish).

D. EPA's Methodology for Assessing Methylmercury Levels in Fish Tissues

To estimate methylmercury levels, including methylmercury attributable to Utility Units, in consumed freshwater fish, EPA's analysis relied primarily on monitoring data (*i.e.*, fish tissue samples collected from freshwater sites across the study area). EPA used sources of national-level monitored Hg data. The

composite UF lead to more conservative RfC. Conversely, lower composite UF are less conservative and usually indicate a higher level of confidence in the RfC. Intermediate UF values or a mixture of high and low UF would require an examination of the relative contribution of various chemicals to the HI. Thus, an HI or HQ greater than 1 may be considered acceptable based on consideration of other factors.

Id. at 125.

National Listing of Fish and Wildlife Advisories (NLFA), which is maintained by EPA, contains data from over 80,000 fish tissue samples across the U.S. In addition to the NLFA, EPA's National Fish Tissue Survey (NFTS) provides useful data. Conducted in 2000–2003, this dataset includes fish tissue samples from 500 randomly selected lakes and reservoirs across the U.S. EPA considers these combined two data sets to be sufficiently comprehensive and sufficiently inclusive of the waterbodies of highest exposure for use in EPA's regional analysis, although, as discussed in the TSD, for certain areas of the country, gaps in the datasets have led EPA to rely on overall regional trends to draw conclusions for local areas.

The NLFA is the most extensive available source of fish tissue sampling data for Hg. It currently includes fish tissue contaminant data collected by states (and submitted to EPA) from over 10,000 locations nationwide, with most of the locations in the eastern half of the U.S. In general, the States historically sampled waterbodies in areas of suspected contamination. More recently, states have also focused sampling efforts on areas of elevated fishing pressure. Almost all of the tissue samples include tests for Hg. The NLFA includes roughly 83,000 Hg samples collected in the U.S. between 1967 and 2002. In the dataset, most samples are described according to the sample location, sample date, measured Hg concentration, species and size of fish, and the part of the fish sampled.

Based on the geographic coordinates provided in the NLFA database, EPA also defined two additional fields for each Hg sample:

—The eight-digit watershed (hydrological unit code (HUC) (discussed below)) in which the sample was located; and

—The type of waterbody (*i.e.*, lake or river/stream) from which the sample was taken.

The HUC, developed by the USGS, spatially delineates watersheds throughout the United States. Hydrologic units are available at four levels of aggregation, ranging from a two-digit regional level (21 units nationwide) to the eight-digit HUC (2,150 distinct units). The eight-digit HUC-level designation is useful for this analysis because it provides a nationally consistent approach for grouping waterbodies on a ''local'' scale (the average HUC area is 1,631 sq mi).[45]

We made the water body type assignments using proximity analysis in ArcINFO. Each sampling site was assigned to either a flowing (*e.g.*, river, stream) or a stationary (*e.g.*, lake, reservoir) waterbody, according the type of waterbody most closely located to the site's lat/long coordinates. We used National Hydrology Dataset (NHD) in the proximity analysis.

For purposes of the modeling described below, we restricted the samples selected from the NLFA data to those that met the following criteria:

- Collected after 1999;
- Sampled from freshwater species (*i.e.*, saltwater species are excluded from the analysis); and
- Sampled from freshwater (rather than estuarine or coastal) waterbodies.

These NLFA Hg sampling data were supplemented with additional observations from EPA's National Fish Tissue Survey (NFTS). Compiled in 2000–2003, this dataset includes fish tissue samples from 500 randomly selected lakes and reservoirs across the U.S. Combining data from NLFA and NFTS, samples from 1633 lake and river sampling sites were selected for the analysis.

Although the NLFA and NFTS provide rich sources of data on Hg levels in freshwater fish for the study area, the fish tissue samples in these databases vary in several respects. For example, they vary according to the size and species of fish sampled and according to the sampling method used (*e.g.*, the cut of fish sampled). We limited the samples we used for this analysis to fish likely to be caught and consumed, defined for this analysis as fish greater than or equal to seven inches in length.

The TSD describes in more detail how we used the data available in the NLFA and NFTS datasets.

E. Air Quality Modeling of the Impacts of Utility Unit Hg on Fish Tissue Levels

EPA conducted computerized modeling that indicates the effects of various scenarios for Utility Unit Hg emissions on fish tissue at the NLFA–NFTS sites across the country, in both a 2001 base case and in projected control cases for the year 2020. This section summarizes the emissions inventories used in those modeling scenarios, and the air quality modeling, that serve as the basis for determining the fish tissue impacts of Hg from Utility Units at various levels of emissions.

EPA used a sophisticated air quality model to estimate baseline and post-control annual total Hg deposition for each scenario. EPA then combined the estimated changes in Hg depositions with fish tissue data to determine estimated changes in methylmercury levels in fish tissues. EPA then combined those changes in fish tissue methylmercury levels with estimates of fish consumption, for use in estimating exposure levels.

1. Air Quality Modeling for Hg Deposition From Utility Mercury Emissions

This section summarizes the methods for estimating Hg deposition for 2001 and 2020 base cases and control scenarios. EPA estimated the Hg deposition changes using national-scale applications of the Community Multi-Scale Air Quality (CMAQ) model in the contiguous United States.

a. CMAQ Model and Hg Deposition Estimates. CMAQ is a three-dimensional grid-based Eulerian air quality model designed to estimate annual particulate concentrations and Hg deposition over large spatial scales (*e.g.*, over the contiguous United States). Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, CMAQ is useful for evaluating the impacts of changes in utility Hg emissions, under various scenarios, on U.S. Hg deposition. Our analysis applies the modeling system to the entire United States for the following emissions scenarios:

(1) A 2001 base year;

(2) A 2001 base year of utility Hg emissions only;

(3) A 2020 projection that includes utility Hg emissions as reduced through implementation of CAIR;

(4) A 2020 projection with utility Hg emissions zeroed-out;[46]

(5) A 2020 projection that includes utility Hg emissions as reduced through implementation of CAMR (which, in turn, reflects both CAIR reductions and the reductions from the additional, 2018 controls); and

(6) A 2020 projection that includes utility Hg emissions as reduced through a second CAMR option (this second CAMR option reflects both CAIR reductions and a set of additional reductions that are tighter than the ones adopted in CAMR).

The CMAQ version 4.3 was employed for this CAMR modeling analysis. This version reflects updates in a number of areas to improve performance and address comments from the peer review. CMAQ simulates every hour of every day of the year and, thus, requires a

[45] More information regarding these hydrological units can be found through the USGS Web site *http://water.usgs.gov/GIS/huc.html.*

[46] The reference to ''zeroed out'' means that the modeled inventory did not include any amount of Hg emissions from utilities. This ''zero-out'' technique allows focus on the impact of the utilities alone.

variety of input files that contain information pertaining to the modeling domain and simulation period. These include hourly emissions estimates and meteorological data in every grid cell, as well as a set of pollutant concentrations to initialize the model and to specify concentrations along the modeling domain boundaries. These initial and boundary concentrations were obtained from output of a global chemistry model. We use the model predictions in a relative sense by first determining the ratio of Hg deposition predictions. The calculated relative change is then combined with the corresponding fish tissue concentration data to project fish tissue concentrations for the future case scenarios.

b. Modeling Domain and Simulation Periods. The modeling domain encompasses the lower 48 States and extends from 126 degrees to 66 degrees west longitude and from 24 degrees north latitude to 52 degrees north latitude. The modeling domain is segmented into rectangular blocks referred to as grid cells. The model actually predicts pollutant concentrations for each of these grid cells. For this application, the horizontal grid cells are roughly 36 km by 36 km. In addition, the modeling domain contains 14 vertical layers with the top of the modeling domain at about 16,200 meters. Within the domain each vertical layer has 16,576 grid cells.

The simulation periods modeled by CMAQ included separate full-year application for each of the emissions scenarios modeled.

c. Model Inputs. CMAQ requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include gridded, hourly emissions estimates and meteorological data and initial and boundary conditions. Separate emissions inventories were prepared for the 2001 base year and each of the future-year base cases and control scenarios. All other inputs were specified for the 2001 base year model application and remained unchanged for each future-year modeling scenario.

CMAQ requires detailed emissions inventories containing temporally allocated emissions for each grid cell in the modeling domain for each species being simulated. The previously described annual emission inventories were preprocessed into model-ready inputs through the emissions preprocessing system. Details of the preprocessing of emissions are provided in the Clean Air Interstate Rule Emissions Inventory Technical Support Document (Emissions Inventory TSD). Meteorological inputs reflecting 2001 conditions across the contiguous United States were derived from version 5 of the Mesoscale Model (MM5). These inputs include horizontal wind components (*i.e.*, speed and direction), temperature, moisture, vertical diffusion rates, and rainfall rates for each grid cell in each vertical layer.

The lateral boundary and initial species concentrations are provided by a three-dimensional global atmospheric chemistry and transport model (GEOS-CHEM). The lateral boundary species concentrations varied with height and time (every 3 hours). Terrain elevations and land use information were obtained from the U.S. Geological Survey database at 10 km resolution and aggregated to the roughly 36 km horizontal resolution used for this CMAQ application.

d. CMAQ Model Evaluation. An operational model performance evaluation for Hg wet deposition for 2001 was performed to estimate the ability of the CMAQ modeling system to replicate base-year wet deposition of Hg. Because measurements for the dry deposition of Hg do not currently exist, the modeled dry deposition performance could not be evaluated. The wet deposition evaluation principally comprises statistical assessments of model versus observed pairs that were paired in time and space on a weekly basis. This evaluation includes comparisons of model predictions to the corresponding weekly measurements from the Mercury Deposition Network (MDN).

As discussed in the TSD, in EPA's view, CMAQ model performance for wet deposition shows very good agreement with the MDN monitoring sites with an underprediction bias well within accepted performance criteria. It should be noted that the application of a sophisticated photochemical grid model like CMAQ has been demonstrated to be appropriate to support national and regional assessments of control strategies on atmospheric concentrations such as today's rule. Therefore, for purposes of assessing impacts on regional patterns of Hg deposition, we aggregate individual CMAQ grids to watersheds.

2. Emission Inventories and Estimated EGU (Utility Unit) Emission Reductions

As discussed in the Clean Air Mercury Rule Emission Inventory Technical Memorandum, EPA developed 2001 and 2020 Hg emission inventories for the air quality modeling. EPA relied on the 2001 Hg emission inventory as the base case. The base case consists of the level of Hg emissions, including Utility Unit emissions reduced by controls implemented for purposes of the acid deposition provisions and for other purposes, before reductions under CAIR (required under CAA section 110(a)(2)(D)) or CAMR (required under section 111). For comparison purposes, EPA also conducted an air quality modeling run of the 2001 Hg emissions inventories with Utility Units' Hg emissions ''zeroed out.'' EPA relied on the Integrated Planning Model (IPM), discussed below, to develop projections of EGU emissions for 2020. The 2020 utility Hg emission inventories reflect reductions under various control scenarios.

a. Use of IPM for Estimating Utility Unit Emissions. EPA projected future Hg emissions from the power generation sector using the IPM. The EPA uses IPM to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia.

IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. The EPA used IPM to project both the national level and the unit level of Utility Unit Hg emissions under different control scenarios. The EPA also used IPM to project the costs of those controls.

As noted elsewhere, the CAIR SO_2 and NO_X controls provide the basis for reducing Hg to the CAIR co-benefit levels in 2010 and 2020. EPA assumed that states would choose to implement the CAIR-required SO_2 and NO_X reductions by controlling Utility Units, and by doing so through the EPA-administered cap-and-trade program. This assumption is reasonable, for present purposes, because of the cost-savings associated with the cap-and-trade program.

EPA used IPM to project the distribution within the utility industry of the emission controls to comply with CAIR. EPA then was able to use IPM to project the amount, and geographic distribution, of Hg emissions that would result from implementation of those CAIR-required emissions controls. In addition, EPA used IPM to project the geographic distribution of the additional emissions controls under section 111, and the associated costs.

In these IPM runs, EPA assumed that states would implement the Hg requirements through the Hg cap-and-trade program that EPA is establishing. EPA further assumed that the States would implement the additional reductions under section 111, beginning in 2010, through the same cap-and-trade program. The cap-and-trade program is implemented in two phases, with a cap

of 38 tons in 2010 (set at the co-benefits reduction under CAIR) and a lower cap of 15 tons in 2018. EPA modeling of section 111 projects banking of excess Hg reductions in the 2010 to 2017 timeframe for compliance with the cap in 2018 and beyond timeframe. Although states are not required to adopt the EPA-administered trading program, this program assures that those reductions will be achieved with the least cost. For that reason, EPA believes it reasonable to assume that States will adopt the program.

The National Electric Energy Data System (NEEDS) contains the generation unit records used to construct model plants that represent existing and planned/committed units in EPA modeling applications of IPM. The NEEDS includes basic geographic, operating, air emissions requirements, and other data on all the generation units that are represented by model plants in EPA's v.2.1.9 update of IPM.

The IPM uses model run years to represent the full planning horizon being modeled. That is, several years in the planning horizon are mapped into a representative model run year, enabling IPM to perform multiple year analyses while keeping the model size manageable. Although IPM reports results only for model run years, it takes into account the costs in all years in the planning horizon. In EPA's v.2.1.9 update of IPM, the years 2008 through 2012 are mapped to run year 2010, and the years 2013 through 2017 are mapped to run year 2015, and the years 2018 through 2022 are mapped to 2020.[47] Model outputs for 2009 and 2010 are from the 2010 run year. More detail on IPM can be found in the model documentation in the docket or at *http://www.epa.gov/airmarkets/epa-ipm* and more discussion of modeled scenarios can be found in the Regulatory Impact Assessment for CAIR and CAMR in the docket.

IPM has been used for evaluating the economic and emission impacts of environmental policies for over a decade. The model's base case incorporates title IV of the Clean Air Act (the Acid Rain Program), the NO_X SIP Call, various New Source Review (NSR) settlements, and several state rules affecting emissions of SO_2 and NO_X that were finalized prior to April of 2004. The NSR settlements include agreements between EPA and certain utilities. IPM also includes various current and future state programs in Connecticut, Illinois, Maine, Massachusetts, Minnesota, New Hampshire, North Carolina, New York, Oregon, Texas, and Wisconsin. IPM includes state rules that have been finalized and/or approved by a state's legislature or environmental agency. The base case is used to provide a reference point to compare environmental policies and assess their impacts and does not reflect a future scenario that EPA predicts will occur.

EPA's modeling is based on various input assumptions that are uncertain, particularly assumptions for Hg control technology, future fuel prices and electricity demand growth. While IPM contains an assumption of 90% Hg removal for ACI and, for modeling convenience, does not constrain the timeframe for the availability of technology, this should not be interpreted as implying any assessment of the availability of technology. For further discussion of the availability of Hg technology, see EPA's Office of Research and Development (ORD) Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, March 2005, in CAMR docket. There may also be technologies available for SO_2 and NO_X control that are not accounted for in IPM. Therefore the technologies that plants may use to comply with this program may not be accurately projected by IPM in all cases. These and other assumptions and uncertainties are discussed further in the RIA for CAIR and CAMR in the docket. More detail on IPM can be found in the model documentation, which provides additional information on the assumptions discussed here as well as all other assumptions and inputs to the model (see docket or *http://www.epa.gov/airmarkets/epa-ipm*).

b. Emission Estimates. The emission sources and the basis for current and future-year inventories are listed in Table VI–1. Table VI–2 summarizes the Hg emissions and the change in the emissions from EGUs (Utility Units) that we expect to result under the various EGU control scenarios (under CAIR and CAMR) that we used in modeling deposition changes.

TABLE VI—1. EMISSION SOURCES AND BASIS FOR CURRENT AND FUTURE-YEAR MERCURY INVENTORIES

Sector	Emissions source	2001 Base year	Future-year base case projections
EGU	Power industry electric generating units (EGUs).	1999 National Emission Inventory (NEI) data.	Integrated Planning Model (IPM).
Non-EGU point sources	Non-Utility Point	1999 NEI, with medical waste incinerator sources replaced with draft 2002 NEI.	(1) Department of Energy (DOE) fuel use projections, (2) Regional Economic Model, Inc. (REMI) Policy Insight® model, (3) decreases to REMI results based on trade associations, Bureau of Labor Statistics (BLS) projections and Bureau of Economic Analysis (BEA) historical growth from 1987 to 2002, (4) Maximum Achievable Control Technology category growth and control assumptions.
Non-point	All other stationary sources inventoried at the county level.	1999 NEI, with medical waste incinerator sources replaced with draft 2002 NEI.	Same as above.

This table documents only the sources of data for the U.S. inventory. The sources of data used for Canada and Mexico are explained in the technical support memorandum and were held constant from the base year to the future years.

[47] An exception was made to the run year mapping for an IPM sensitivity run that examined the impact of a NO_X Early Reduction Pool (ERP). In that run the years 2009 through 2012 were mapped to 2010 and 2008 was mapped to 2008.

TABLE VI—2. SUMMARY OF MODELED MERCURY EMISSIONS FOR CLEAN AIR MERCURY RULE

	Elemental mercury	Reactive gaseous mercury	Particulate mercury	Total mercury
2001 Base Case Emissions (tons)				
EGU Sources	26.26	20.58	1.73	48.57
Non-EGU Point Sources	37.85	13.33	7.60	58.78
Area Sources	5.05	1.53	0.96	7.54
All Sources	69.16	35.44	10.29	114.89
2001 Utility Mercury Emissions Zero-Out (tons)				
EGU Sources	0.00	0.00	0.00	0.00
Non-EGU Point Sources	37.85	13.33	7.60	58.78
Area Sources	5.05	1.53	0.96	7.54
All Sources	42.90	14.86	8.56	66.32
2020 With CAIR Emissions (tons)				
EGU Sources	25.72	7.87	0.83	34.42
Non-EGU Point Sources	28.03	10.37	6.61	45.01
Area Sources	5.69	1.30	0.77	7.76
All Sources	59.44	19.54	8.21	87.19
2020 With CAIR Utility Mercury Emissions Zero-Out				
EGU Sources	0.00	0.00	0.00	0.00
Non-EGU Point Sources	28.03	10.37	6.61	45.01
Area Sources	5.69	1.30	0.77	7.76
All Sources	33.72	11.67	7.38	52.77
2020 With CAIR and CAMR				
EGU Sources	17.65	6.57	0.83	25.05
Non-EGU Point Sources	28.03	10.37	6.61	45.01
Area Sources	5.69	1.30	0.77	7.76
All Sources	51.37	18.24	8.21	77.82
2020 With CAIR and Alternative CAMR Control Option				
EGU Sources	14.33	5.71	0.79	20.83
Non-EGU Point Sources	28.03	10.37	6.61	45.01
Area Sources	5.69	1.30	0.77	7.76
All Sources	48.05	17.38	8.17	73.60

(**Note:** ''Reactive Gaseous Mercury'' refers to oxidized mercury).

(**Note:** Table IV–2 includes projections for all EGUs, including other fossil-fired units, and coal-fired units that are less than 25 MW.)

c. Projected Hg Emissions. Table VI–3 provides projected total Hg emissions levels in 2010, 2015, and 2020. Because of the banking of excess emissions reductions under the first phase of the Hg program, emissions in the second phase will be initially higher than the caps that are required under CAMR.

TABLE VI—3. PROJECTED EMISSIONS OF HG WITH THE BASE CASE [a] (NO FURTHER CONTROLS), WITH CAIR, AND WITH SECTION 111 CONTROLS

[Tons]

	2010	2015	2020
Base Case	46.6	45.0	46.2
CAIR	38.0	34.4	34.0
CAMR	31.3	27.9	24.3
Alternative CAMR Control Option	30.9	25.7	20.1

[a] Base case includes Title IV Acid Rain Program, NO_X SIP Call, and state rules finalized before March 2004.
Source: Integrated Planning Model run by EPA.

Emissions projections are presented for affected coal-fired units.

(**Note:** Table VI–3 includes projections for all affected units, *i.e.*, coal-fired units greater than 25 MW.)

3. Effect of Reductions in Utility Unit Hg Emissions on Regional Patterns of Mercury Deposition and Fish Tissue Methylmercury Concentrations

EPA uses CMAQ to predict the effect of the various control scenarios on Hg deposition attributable to Utility Units within the 48 contiguous states. By averaging the 36 km CMAQ gridded deposition estimates to the watershed (*i.e.*, HUC–8) level, EPA is able to estimate the effectiveness of reductions in utility Hg emissions in achieving reductions in deposition attributable solely to Utility Units. In addition, by comparing changes in Hg deposition before and after implementation of rule requirements at the geographic location of the fish tissue sample points, EPA is able to estimate the effect of reductions in Hg deposition on fish tissue methylmercury concentrations at the sample points.

EPA generates these changes in Hg deposition by comparing two air modeling scenarios (*e.g.*, a control scenario versus a baseline scenario for a particular simulation year). EPA then translates these changes in Hg deposition into changes in methylmercury fish tissue concentrations based on a proportionality assumption: *i.e.*, an incremental percent change in deposition produces a matching percentage change in Hg fish tissue concentrations.[48]

EPA is able to use these modeled changes in methylmercury fish tissue concentrations, together with information about fish consumption, to predict changes in population-level Hg exposure. These exposure changes reveal the extent to which reductions in Utility Unit Hg emissions, and the extent to which remaining Utility Unit Hg emissions, affect public health.

F. Fish Tissue Levels of Methylmercury Modeled To Result After Implementation of CAIR and CAMR

This section describes the amounts of Utility Unit attributable Hg deposition onto watersheds (termed HUC), as well as the Utility-attributable methylmercury in fish tissue, all under the various control scenarios modeled.

1. Utility-Attributable Hg Deposition Patterns

The air quality modeling shows that total Hg deposition is not highly impacted by utility deposition. The small size of this impact is evident when utility emissions are, in effect, zeroed out in the 2001 base case. The following tables summarize impacts on total Hg deposition and Hg deposition attributable to Utility Units.

TABLE VI–4.—SUMMARY STATISTICS FOR TOTAL HG DEPOSITION

[Aggregated to the HUC–8 level]

	2001 Base case	2001 Utility zero out	2020 Base case (with CAIR)	2020 Utility zero out	2020 CAMR requirements	2020 CAMR alternative
Minimum	6.94	6.94	6.08	5.90	6.08	6.07
Maximum	54.54	54.38	62.76	62.72	62.76	62.75
50th percentile	15.92	14.60	14.59	13.92	14.44	14.39
90th percentile	22.16	19.48	19.46	19.04	19.37	19.33
99th percentile	32.35	27.20	29.15	28.93	28.96	28.95

(All units are expressed in micrograms per square meters.)

TABLE VI–5. SUMMARY STATISTICS FOR UTILITY ATTRIBUTABLE HG DEPOSITION

[aggregated to the HUC–8 level]

	2001 Base case	2020 Base case (with CAMR)	2020 CAMR Requirements	2020 CAMR Alternative
Minimum	0.00	0.00	0.00	0.00
Maximum	19.71	4.03	3.85	3.80
50th percentile	0.39	0.3	10.26	0.22
90th percentile	4.08	1.38	1.16	0.99
99th percentile	10.15	2.56	2.17	2.04

(All units are expressed in micrograms per square meters.)

The median deposition level is reduced by only 8 percent when utilities emissions are zeroed out in 2001, suggesting that utilities are not a major source of Hg deposition in most HUCs. Even so, at HUCs with the highest deposition levels, zeroing out utilities reduces the 99th percentile deposition level by 16 percent, suggesting that there are relatively larger impacts of utilities in high deposition areas.

By 2020, after implementation of CAIR, significant reductions in deposition attributable to utilities occurs. HUCs with high levels of utility deposition receive a larger reduction in Utility-attributable Hg deposition relative to HUCs with a relatively small level of Utility-attributable deposition. Specifically, CAIR results in a 75 percent reduction in the 99th percentile of Utility-attributable deposition, and a 20 percent reduction in the 50th percentile. CAIR also shifts the distribution of utility-attributable deposition. In the 2001 base case, 10 percent of HUCs had greater than 20 percent of deposition attributable to utilities. In the 2020 post-CAIR base case, no HUCs had greater than 20 percent of deposition attributable to utilities, and 90 percent had less than 9 percent of deposition attributable to utilities.

[48] US EPA, 2001. Mercury Maps: A Quantitative Spatial Link Between Air Deposition and Fish Tissue: Peer Reviewed Final Report. EPA–823–R–01–009. Mercury Maps is discussed at length in the TSD.

Additional reductions in Hg emissions due to the CAMR requirements result in relatively small additional shifts in the distribution of deposition. Additional emissions reductions due to the CAMR requirements result in a small additional reduction in the number of HUCs with a high percentage of utility-attributable emissions. (The incremental impact of the CAMR alternative relative to the promulgated CAMR requirements is very small.)

2. EGU-Attributable Methylmercury Fish Tissue Levels

The following tables summarize the methylmercury fish tissue levels associated with the various Utility Unit Hg emissions scenarios. All units refer to mg (of methylmercury) per kg (fish tissue), or parts per million (ppm). As a frame of reference, it should be noted that EPA's default water quality criterion is 0.3 mg/kg.

TABLE VI—6. SUMMARY STATISTICS FOR TOTAL FISH TISSUE METHYLMERCURY

[Sample locations]

	2001 Base case	2001 Utility zero out	2020 Base case CAIR	2020 Zero out	2020 CAMR requirements	2020 CAMR alternative
Minimum	0.00	0.00	0.00	0.00	0.00	0.00
Maximum	4.49	3.64	3.65	3.46	3.63	3.61
50th percentile	0.25	0.21	0.21	0.20	0.21	0.21
90th percentile	0.90	0.81	0.79	0.77	0.79	0.78
99th percentile	1.80	1.65	1.64	1.57	1.63	1.63

(All units are in mg methylmercury per kg fish tissue.)

TABLE VI—7. SUMMARY STATISTICS FOR UTILITY ATTRIBUTABLE FISH TISSUE METHYLMERCURY

[Across sampling locations]

	2001 Base	2020 (with CAIR)	2020 CAMR Requirements	2020 CAMR Alternative
Minimum	0.00	0.00	0.00	0.00
Maximum	0.85	0.25	0.19	0.18
50th percentile	0.03	0.01	0.01	0.01
90th percentile	0.11	0.03	0.03	0.03
99th percentile	0.26	0.10	0.09	0.08

(All units are in mg methylmercury per kg fish tissue.)

a. 2001 Base case and 2001 Utility Zero-out. In the 2001 base case, as a result of all international and U.S. emissions, and before U.S. utilities implement reductions from CAIR or CAMR, the 50th percentile of the sample points had an estimated methylmercury fish tissue concentration of 0.25 mg/kg. The 90th percentile water body had an estimated methylmercury fish tissue concentration of 0.90 mg/kg, and the 99th percentile had 1.80 mg/kg.

The amount of methylmercury attributable solely to utilities in the 2001 base case, which becomes evident when utilities are zeroed out, is of course much smaller. The 50th percentile of the sample points had an estimated methylmercury fish tissue concentration. attributable solely to utilities, of 0.03 mg/kg. The 90th percentile had 0.11 mg/kg, the 99th percentile had 0.26 mg/kg, and the maximum individual sample point had 0.85 mg/kg.

It should be recalled that EPA recommends the water quality criterion of 0.3 mg/kg as a level that, given fish consumption at the 90th percentile level, would result in exposure levels below the RfD. For present purposes, EPA does not consider the water quality criterion of 0.3 mg/kg as a bright-line test for evaluating fish tissue methylmercury levels attributable to U.S. Utility Units. Rather, the criterion serves as establishing a broad frame of reference, that serves to place into context both the overall methylmercury fish tissue levels (which are attributable to methylmercury from all sources) and the methylmercury levels attributable to Utility Units.

These results indicate the relatively small percentage of U.S. utility contribution to U.S. fish tissue methylmercury levels.

b. 2020: Utilities With CAIR Reductions. EPA's modeling shows that in 2020, as a result of all international and U.S. emissions, and with U.S. utilities implementing reductions from CAIR (but not CAMR), the 50th percentile of the sample points is projected to have a methylmercury fish tissue concentration of 0.21 mg/kg. The 90th percentile is projected to have 0.79 mg/kg, and the 99th percentile is projected to have 1.64 mg/kg.

The amount of methylmercury in fish attributable solely to utilities in 2020, after implementation of the CAIR reductions (but, again, before CAMR), of course is smaller. The 50th percentile of the sample points is projected to have fish tissue concentration, attributable solely to utilities of 0.01 mg/kg. The 90th percentile is projected to have 0.03 mg/kg, the 99th percentile is projected to have 0.10 mg/kg, and the maximum individual sample point (*i.e.*, the one with the highest methylmercury levels) is projected to have 0.25 mg/kg.

Again, using the 0.3 mg/kg methylmercury water quality criterion as a broad frame of reference serving to place in context both the overall methylmercury fish tissue levels (attributable to methylmercury from all sources) and the methylmercury fish tissue levels attributable to Utility Units, it is clear that the latter levels, following implementation of CAIR, are low.

c. 2020: Utilities with CAMR Controls. The CAMR level of controls achieve further, albeit small, reductions in methylmercury fish tissue concentrations. Compared to the CAIR controls, the CAMR controls would further reduce, in 2020, methylmercury fish tissue concentrations by, in the 99th percentile, 0.01 mg/kg.

d. 2020: Utilities with Alternative CAMR Controls. EPA evaluated, but did not adopt, a slightly tighter level of CAMR controls. These alternative

CAMR controls would have achieved still further, albeit, again small, reductions in Hg deposition and in fish tissue methylmercury levels. Compared to the CAIR controls, these alternative CAMR controls would reduce methylmercury fish tissue levels in 2020 by, in the 99th percentile, 0.02 mg/kg.[49]

5. Overall Impact of CAIR and CAMR Controls on Utility Unit Hg Emissions

As described in the CAIR rule, CAIR reduces EGU Hg emissions from pre-CAIR levels by a substantial percentage. CAMR reduces Utility Unit Hg emissions, from CAIR levels, by 27 percent. CAMR reduces ionic Hg emissions, those that are most likely to result in local and regional deposition, by 17 percent relative to CAIR levels.

These reductions tend to occur from the largest sources. That is, the larger the source of Hg emissions, the more likely it is to implement CAIR or CAMR controls, and therefore the more likely it is to reduce its Hg emissions. More specifically, under the cap-and-trade system, the marketplace tends to direct controls to the largest emitters because those emitters can achieve the most cost-effective reductions. Compared to smaller emitters, these larger emitters have an incentive to implement more stringent controls, thereby reducing their emissions further below the level of their allowances, and thereby generating a larger number of allowances for sale to defray control costs. See ''Proposed National Emissions Standards for Hazardous Air Pollutants; and in the Alternative, Proposed Standards of Performance for New and Existing Sources: Electric Utility Steam Generating Units,'' 9 FR 4652, 4702–03 (Jan. 30, 2004).

G. Exposure to Utility-Attributable Methylmercury Levels in Fish Tissue

CAIR reduces median Utility-attributable fish tissue methylmercury levels, from pre-CAIR levels, by 67 percent. CAIR reduces the 99th percentile Utility-attributable fish tissue methylmercury levels, from pre-CAIR levels, by 60 percent. CAMR reduces median Utility-attributable fish tissue methylmercury levels, from CAIR levels, by 12 percent. CAMR reduces the 99th percentile Utility-attributable fish tissue methylmercury levels, from CAIR levels, by 9 percent.

As a result of these reductions, after CAIR or CAMR, no sample site remains in which Utility-attributable, emissions cause methylmercury fish tissue levels to exceed 0.3 mg/kg (EPA's water quality criterion).

Even with these reductions, although the levels of methylmercury in fish tissues attributable to Utility Units are small, the magnitude of methylmercury exposure depends on consumption levels and the sensitivity of the individual. For purposes of assessing whether utility Hg emissions are reasonably anticipated to result in hazards to public health, we focused on evaluating utility attributable methylmercury exposures for women of childbearing age in the general U.S. population who consume non-commercial (*e.g.,* recreational) freshwater fish in U.S. waterbodies.

This section describes available information as to the consumption levels of women of child-bearing age within the population of recreational fishers who consume at typical levels, and within high-consumption sub-populations; and discusses the amounts of methylmercury that may be ingested as a result of those consumption levels.

1. General Population

We believe that only those women of childbearing age who consume noncommercially caught U.S. freshwater fish have the potential for significant exposures to utility-attributable methylmercury. As a result, our assessment of the hazards to public health focuses on those women.

2. Recreational Fishers Who Consume Fish At Typical Levels.

a. Consumption Levels. For our analysis of recreational freshwater fish consumption, EPA has determined that the sport-caught fish consumption rates for recreational freshwater fishers specified as ''recommended'' in the EPA's Exposure Factors Handbook (mean of 8 gm/day and 95th percentile of 25 gm/day), represent the most appropriate values for present purposes. These recommended values were derived based on ingestion rates from four studies conducted in Maine, Michigan, and Lake Ontario (Ebert *et al.,* 1992; Connelly *et al.,* 1996; West *et al.,* 1989; West *et al.,* 1993). These studies are suitable because they included information for annual-averaged daily intake rates for self-caught freshwater fish by all recreational fishers including consumers and non-consumers. The mean values presented in these four studies ranged from 5 to 17 gm/day, while the 95th percentile values ranged from 13 to 39 gm/day.[50]

The EPA ''recommended values'' were developed by considering the range and spread of means and 95th percent values presented in the four studies. EPA recognizes that use of mean and 95th percentile consumption rates based on these four studies may not be representative of fishing behavior in every state and that there may be regional trends in consumption that differ from the values used in this analysis. However, EPA believes that these four studies represent the best available data for developing recreational fisher ingestion rates for present purposes.

As a result, for today's purposes of evaluating the potential for health effects for consumers of recreational freshwater fish resulting from exposure to utility-attributable methylmercury, we consider both the mean of 8 gm/day consumption and the 95th percentile amount of 25 gm/day.

b. Levels of Consumption Combined with Levels of Utility-Attributable Methylmercury in Fish Tissue. As described above, fish tissue levels of Utility-attributable methylmercury, for virtually all sample points, are only a fraction of the 0.3 mg/kg (fish tissue) water quality criterion. EPA evaluated recreational fish consumers' exposure to this Utility-Attributable methylmercury by calculating the level of exposure to this methylmercury and comparing it to the RfD when background exposures are not considered. For the purposes of assessing population exposure due solely to power plants, we create an index of daily intake (IDI).The IDI is defined as the ratio of exposure due solely to power plants to an exposure of 0.1 μug/kg bw/day. The IDI is defined so that an IDI of 1 is equal to an incremental exposure equal to the RfD level, recognizing that the RfD is an absolute level, while the IDI is based on incremental exposure without regard to absolute levels. Note that an IDI value of 1 would represent an absolute exposure greater than the RfD when background exposures are considered.

At either the mean fish consumption rate of 8 gm/day or the 95th percentile fish consumption rate of 25 gm/day for recreational fish consumers discussed above, and using the 99th percentile methylmercury fish tissue concentration attributable to Utility Unit (and a typical body weight of 64 kg for women of child-bearing age), the calculated Utility-attributable methylmercury exposures are 0.013 μug/kg body weight per day and 0.04 μug/kg body weight per day, respectively. Both calculated exposures are well below the RfD of 0.1 μug/kg body weight per day (an IDI value well below 1).

[49] A detailed discussion of the control alternatives we considered and the reason for our final selection is contained in the preamble to the final CAMR.

[50] The 39 gm/day value actually represents a 96th percentile value.

EPA uses the RfD to place ingestion levels in context. The RfD level of methylmercury ingestion—0.1 µug/kg body weight—should not be considered a bright line standard above which adverse health effects occur, but rather as an aid in establishing the context for evaluating both overall methylmercury ingestion (arising from methylmercury from all sources) as well as Utility-Attributable methylmercury ingestion in light of consumption rates. Our analysis concludes that Utility Unit Hg emissions do not cause hazards to the health of the general public or higher fish consuming recreational anglers.

3. High-Level Fish Consumption Sub-Populations

Although exposure to Utility-attributable methylmercury from freshwater fish tissue is quite low for recreational fishers generally, as just described, EPA recognizes that certain sub-populations consume higher levels of U.S. freshwater fish. These populations may include a subset of recreational fishers who consume large quantities of fish, individuals who are subsistence fishers, and individuals who are part of certain ethnic groups. EPA is aware that at very high consumption levels, even relatively small concentrations of methylmercury in fish may result in exposures that exceed the RfD.

However, as described in the TSD, characterization of fish consumption rates for the highest fish consuming subpopulations (*e.g.,* Native American and other ethnic populations exhibiting subsistence-like consumption) in the context of a larger regional or national analysis is technically challenging. Peer reviewed study data on these populations is relatively limited, especially when subjected to the criteria outlined in the TSD. Many of the high consumption groups that have been studied are located near the ocean and consequently have a significant fraction of their overall exposure comprised of saltwater fish. In addition, some of these studies provide details on seasonal consumption rates, but do not integrate these rates to provide an overall mean annual-averaged consumption rate relevant to an RfD-based analysis.

Although many of these studies provide mean consumption rates, few have identified specific high-end percentile values (*e.g.,* 90th, 95th or 99th percentile consumption rates). Instead, many studies, including a number of non-peer reviewed sources, cite non-specific high-end or bounding point estimates (*e.g.,* the range of consumption rates for the Ojibwe submitted for the CAMR NODA). While these point values can be used in developing high-end bounding scenarios for evaluating risk to these groups, they do not support population-level analysis of exposure since they cannot be used to fit distributions characterizing variability in fish consumption rates across these sub-populations (as noted above, modeling of population-level exposures requires that distributions characterizing fish consumption rates across a particular population be developed).

An additional challenge in characterizing high-level fish consumption is that care needs to be taken in extrapolating study results from one group to another. This reflects the fact that high-level fish consumption is often tied to socio-cultural practices and consequently consumption rates for a study population cannot be easily transferred to other groups which may have different practices (*e.g.,* practices for one Native American tribe may not be relevant to another and consequently behavior regarding fish consumption may not be generalized).

Despite these challenges in characterizing high-level consumption, EPA has developed recommended subsistence-level fish consumption rates of 60 g/day (mean) and 170 g/day (95th percentile) (EPA, 1997, Exposure Factors Handbook). These values are based on a study of several Native American Tribes located along the Columbia River in Washington State. Although these consumption rates are specific to the tribes included in the study and reflect their particular socio-cultural practices (including seasonality and target fish species), EPA believes that this study does provide a reasonable characterization of high-consuming subsistence-like freshwater fishing behavior (EPA, 1997, Exposure Factors Handbook). Therefore, in the absence of data on local practices, EPA recommends that these consumption rates be used to model high-consuming groups in other locations. It is important to note that, as explained above, application of these subsistence consumption rates outside of the original Columbia River study area could be problematic because it would be difficult to transfer these consumption rates to a different group that might exhibit different fishing behavior. However, these recommended rates can be used to model subsistence scenarios at different locations.

Although these subsistence consumption rates are recommended by EPA, commenters (including NODA comments obtained for this rule), have identified alternative consumption rates for specific high consuming groups that are in some instances, higher than these recommended values. For example, a survey by the Great Lakes Indian Fish and Wildlife Commission (GLIFWC) (as referenced in comments to the CAMR NODA) indicates that consumption rates by members of Ojibwe Great Lakes tribes during fall spearing season may range from 155.8–240.7 g/day and may range from 189.6–292.8 g/day during the spring. EPA has reviewed these comments and does not believe that it would be appropriate to rely on them for purposes this rulemaking. First, the data has not been peer reviewed. Moreover, it is not clear from the comments how many people consume fish at those rates, to what extent those fish consumers are women of child-bearing years, and how to annualize these seasonal sales.[51]

For all the above reasons, and despite comments indicating that some subgroups may have larger short-term consumption rates, EPA believes that the Columbia River-based consumption rates of between 60 g/day (mean) and 170 g/day (95th percentile) are appropriate default values for subsistence fish consumers.

H. EPA Concludes That Utility Hg Emissions Remaining After Imposition of Other Requirements of the Act, in Particular CAA Sections 110(a)(2)(D) and 111, Do Not Result in Hazards to Public Health

As discussed above, Congress mandated that EPA assess hazards to public health reasonably anticipated to occur as a result of utility HAP emissions remaining after imposition of the requirements of the Act, and to regulate Utility Units under section 112 if EPA determines that such regulation is ''appropriate'' and ''necessary.'' The issue of whether the level of Hg emissions from Utility Units remaining after implementation of CAA section 110(a)(2)(D), and independently section 111, cause hazards to public health is directly relevant to our conclusion set forth in section IV.A. above, namely, that it is not appropriate to regulate coal-fired Utility Units under section 112 on the basis of Hg emissions. For the reasons discussed below, EPA concludes that the level of Hg emissions remaining after implementation of CAIR, and, independently, CAMR, which implement sections 110(a)(2)(D) and 111, respectively, do not result in hazards to public health.

1. ''Hazards to Public Health'' Under Section 112(n)(1)(A)

[51] As discussed below, the Ojibwe Great Lakes tribes do not appear to be located in areas with high utility-attributable Hg deposition.

Section 112(n)(1)(A) establishes the backdrop against which our utility ''appropriate and necessary'' determination should be judged. Again, we must decide whether we reasonably anticipate utility Hg emissions remaining after imposition of the requirements of the Act to cause hazards to public health. If they do, then we must determine whether it is appropriate and necessary to regulate Utility Units under section 112. If utility Hg emissions do not cause public health hazards, however, which indeed is what we conclude today, then it is not appropriate to regulate such emissions under section 112, and there is no need to proceed to the ''necessary'' prong of the section 112(n)(1)(A) inquiry, as explained above.

Section 112(n)(1)(A) defines neither what constitutes a ''hazard'' to public health nor what EPA's obligations would be if such hazard were identified. Therefore, we believe that EPA has wide discretion, using its technical expertise, to define ''hazards to public health,'' and to determine whether Hg emissions from utilities pose such a hazard. EPA's judgment should only be overturned if it is deemed unreasonable, not merely because other, reasonable alternatives exist. *Department of Treasury* v. *FLRA,* 494 U.S. 922, 933 (1990); *Texas Office of Public Utility Counsel* v. *FCC,* 265 F.3d 313, 320 (5th Cir. 2001).

Although section 112(n)(1)(A) does not define ''hazards to public health,'' section 112(n)(1)(C) offers guidance with respect to determining whether Hg emissions result in hazards to public health. In that section, Congress asked the National Institute of Environmental Health Sciences to conduct a study to determine the ''threshold level of mercury exposure below which adverse *human health* effects are not expected to occur.'' (Emphasis added) Congress further mandated that the study include a threshold for Hg concentrations in fish tissue which may be consumed, including consumption by *''sensitive populations''* without adverse effects on *public health.* Implicit in this direction, is that Congress was concerned, first about public health, not environmental effects. EPA has identified the exposure to Hg through consumption of contaminated fish as a pathway to human health effects, and EPA has also, in its discretion, looked at the health effects on sensitive populations.

In interpreting what ''hazards to public health'' might be reasonably anticipated under section 112(n)(1)(A), we think it is also useful to look at the DC Circuit's Vinyl Chloride decision, 824 F.2d 1146 (1987), and the analysis EPA articulated in its so-called ''benzene'' analysis, 54 FR 38044 (Sept. 14, 1989). Although the Vinyl Chloride decision and ''benzene'' analysis address the issue of how to protect public health ''with an ample margin of safety,'' and are thus more stringent than the standard established in section 112(n)(1)(A), we nevertheless believe that the general principles articulated in Vinyl Chloride and the ''benzene'' analysis are relevant to our analysis of assessing hazards to public health pursuant to section 112(n)(1)(A). Some of those key principles include: (1) ''Safe'' does not mean ''risk free,'' (Administrator is to determine what risks are acceptable in the world in which we live, where such activities as driving a car are considered generally safe notwithstanding the known risk involved), Vinyl Chloride, 824 F.2d at 1165; (2) something is '' 'unsafe' only when it threatens humans with a significant risk of harm,' '' *id.* at 1153; (3) EPA, not the courts, has the technical expertise to determine what risks are acceptable, *id.* at 1163; (4) EPA is permitted to account for uncertainty and to use ''expert discretion to determine what action should be taken in light of that uncertainty,'' *id.;* and (5) in determining what is ''safe'' or ''acceptable,'' EPA should consider a variety of factors, including: (a) Estimated risk to a maximally exposed individual (the so-called ''maximum individual risk'' or ''MIR''); (b) overall incidence of cancer or other serious health effects within the exposed population; (c) the numbers of persons exposed within each individual lifetime risk range; (d) the science policy assumptions and uncertainties associated with the risk measures; (e) weight of the scientific evidence for human health effects; and (f) other quantified or unquantified health effects. (See 54 FR at 38045–46, 38057).

In assessing whether remaining utility HAP emissions pose hazards to public health, consistent with section 112(n)(1)(C) and the above identified factors, we looked at the public's, including sensitive populations' (*i.e.,* fish consumers), exposure to methylmercury through fish consumption attributable to utilities alone. Based on this assessment, and as explained further below, EPA concludes that remaining utility HAP emissions do not pose hazards to public health.

2. CAIR and CAMR Reduce the Public's Methylmercury Exposure Due to Fish Consumption to Below the Methylmercury RfD (Below an IDI Value of 1)

As discussed above, EPA has adopted a water quality criterion for methylmercury for states to use in establishing water quality standards to protect public health. The criterion, expressed as a fish tissue concentration, of 0.3 mg/kg was derived from the methylmercury RfD (taking into account the possibility that a person may be exposed to methylmercury via commercial fish to some degree, as expressed in the RSC described elsewhere). At this level, people consuming at a high-end fish consumption rate of 17.5 grams per day would not be exposed above the methylmercury RfD. As noted above, this value represents the 90th percentile fish consumption rate.

In the base year of 2001 (*i.e.,* prior to both CAIR and CAMR), fish-tissue methylmercury concentrations at the 90th percentile, 99th percentile, and maximum (that is, the single highest concentration) levels, attributable to utilities, are 0.11, 0.27, and 0.85 mg/kg, respectively. CAIR reduces the utility-attributable methylmercury fish-tissue concentrations at the 90th percentile, 99th percentile, and maximum level to 0.03, 0.10, and 0.25 mg/kg, respectively. CAMR reduces these concentrations even further to 0.03, 0.09, and 0.19 mg/kg, respectively. These post CAIR and CAMR levels are considerably below the methylmercury water quality criterion of 0.3 mg/kg.

At all of these post-control methylmercury levels, fish consumers at the water quality criterion 90th percentile consumption level of 17.5 grams per day are well below the RfD (below an IDI value of 1). Further, these concentration values when applied to the 95th percentile consumption rate for recreational freshwater anglers identified in EPA's Exposure Factors Handbook, *i.e.,* 25 grams per day, also result in exposures below the RfD (below an IDI value of 1). As a result, it is evident that the general population (which is expected to consume less U.S. freshwater fish than recreational anglers) does not confront hazards to public health from utility-attributable methylmercury.

At the methylmercury fish tissue concentrations attributable to utilities remaining after implementation of CAIR and CAMR, it is possible that consumers eating at the subsistence-level fish consumption rates of 60 g/day (mean) and 170 g/day (95th percentile), see Exposure Factors Handbook, could exceed the RfD (an IDI value greater than 1) as a result of utility-attributable emissions if they are in fact consuming fish from the most contaminated locations. In other words, for a fish consumer to exceed the RfD (an IDI value greater than 1) as a result of utility

Hg emissions, they have to both (1) consume fish at the highest consumption rates and (2) consume fish from waterbodies with the highest levels of utility-attributable Hg fish-tissue concentrations. As discussed in the TSD, the probability of these factors converging is quite low. For example, after CAIR, the probability that a recreational angler will exceed the RfD (an IDI value greater than 1) exclusively as a result of utility Hg emissions is only 0.01 percent. After CAMR, the probability drops even lower. Our analysis further shows that even if there were a convergence of the unlikely factors of consuming at the 99th percentile consumption rates and at the 99th percentile methylmecury fish tissue concentrations, exposure would exceed the RfD by only 10 percent (an IDI value of 1.1). Exceeding the RfD by this amount (an IDI value of 1.1) does not mean that an adverse effect will occur. Indeed, 10 percent above the RfD (an IDI value of 1.1), or 0.11 µg/kg-bw/day, is below the World Health Organization's level of 0.23 µg/kg-bw/day.[52]

Consumption rates for subsistence fishers are much higher than recreational anglers. As such, these populations have a greater probability of exceeding the RfD (an IDI value greater than 1). For this to happen, the subsistence fisher still must be at the high-end of the distribution for both consumption and utility-attributable methylmercury fish tissue concentrations. Our statistical data suggest that subsistence anglers at the 99th percentile consumption rate and the 99th percentile concentration level could exceed the RfD (an IDI value greater than 1). Holding consumption rates at the 99th percentile, the subsistence angler will likely exceed the RfD (an IDI value greater than 1) at or above the 72nd percentile fish tissue concentration.

Again, the likelihood of this occurring is very small. Specific data on concentrations in fish at waterbodies frequented by subsistence fishing populations has not been generated. To get a sense of tribal location in relation to utility-attributable Hg deposition post-CAIR, we overlaid the 2000 Census data on the location of Native American populations (by census tract) on our CMAQ models. Visual inspection of the resulting map shows that the overwhelming majority of tribal populations live outside of areas most impacted by utility-attributable Hg deposition. *See* TSD. This suggests that the 99th percentile of the utility attributable methylmercury concentrations is likely inappropriate as an upper bound for Native American exposures, further reducing the probability that, post CAIR, and even more so, post CAMR, an individual Native American (who comprise a significant percent of upper-bound subsistence anglers) will exceed the RfD (an IDI value greater than 1).

As discussed above, EPA received comments on the consumption rates of certain ethnic groups that are higher than the subsistence angler consumption rate that EPA relied on for purposes of this analysis. Specifically, members of the Ojibwe Great Lakes Tribes commented that during their fall spearing season they may consume between 156 and 241 grams of fish per day, and during their spring spearing season, they may consume as much as 293 grams/day. For a number of reasons, EPA found the data to be of limited value. First, the data have not been peer reviewed and thus EPA is reluctant to rely on them for regulatory purposes. Second, commenters did not include information on annual average consumption rates or the percentage of those fish consumers that are women of childbearing age. Third, based on EPA's information, the Tribes do not reside in an area that appears to be significantly impacted by utility Hg emissions. Thus, despite having extremely high consumption rates, there are no data in the record that suggest that members of the Tribe would be exposed above the RfD (an IDI value greater than 1) as a result of utility emissions. And again, as discussed in greater detail below, exposure above the RfD does not necessarily equate to adverse effects.

3. The RfD Is An Appropriate Health Benchmark

As described in section VII.B., in general, the RfD is ''an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime.'' [53] EPA's RfD for Methylmercury is 0.1 µg/kg bw/day, which is 0.1 microgram of Hg per day for each kilogram of a person's body weight. Since the most sensitive subpopulations are factored into the RfD, its use is thought to be protective of all life stages without additional uncertainty factors or adjustments. The National Academy of Sciences (NAS) reviewed the toxicological effects of Methylmercury and concluded that ''[o]n the basis of its evaluation, the committee's consensus is that the value of EPA's current RfD for Methylmercury, 0.1 µg/kg per day, is a *scientifically justifiable level for the protection of public health.*'' [54]

EPA views the level of the RfD as establishing the overall context for assessing the health effects of ingesting utility-attributable Methylmercury. As noted above, in regulating HAPs that constitute threshold pollutants, EPA has stated that the risks associated with exposures below the RfD generally should be considered to be acceptable, and that the emissions associated with those exposures need not be regulated further under section 112.

However, the RfD should not be considered a bright line. At exposures above the RfD, ''adverse health effects are possible,'' but such exposures ''[do] not necessarily mean that adverse effects will occur.'' Indeed, the World Health Organization has concluded that a level equal to 2.3 times EPA's Methylmercury RfD is protective of human health.

4. Risks Remaining After Implementation of CAIR, and Even More So After CAMR, Are Acceptable

Applying the risk factors identified above to utility Hg emissions in the 112(n)(1)(A) context, EPA concludes that utility Hg emissions remaining after implementation of CAIR, and even more so after CAMR, do not pose unacceptable hazards to public health. The overwhelming majority of the general public and high-end fish consumers (at least through the 99th percentile of recreational anglers) are not expected to be exposed above the methylmercury RfD (an IDI value greater than 1). While the possibility exists that a very small group of people may be exposed above the RfD (an IDI value greater than 1), significant uncertainties exist with respect to the existence and

[52] The choice of an ''acceptable'' risk level is one of policy informed by science. The RfD does not represent a ''bright line'' above which individuals are at risk of significant adverse effects. Rather, it reflects a level where EPA can state with reasonable certainty that risks are not appreciable. The Agency further notes that a number of other national and international scientific bodies have assessed the health effects of Hg and have adopted levels greater than EPA's RfD. As exposure levels increase beyond the RfD, the possibility of deleterious effects increases, but the point at which they become ''unacceptable'' must be determined on a case-by-case basis. In making this determination, the Agency considers a number of factors including: (1) Confidence in the risk estimate: How certain is the scientific information supporting the link between possible health effects and exposures?; (2) the effects of concern: How serious are the health effects?; (3) the size of the population at risk, as well as the distribution of risk within the population. The Agency has considered these factors in the case of Hg and has concluded that the exposures above the IDI described elsewhere in this chapter do not constitute an unacceptable risk.

[53] *See http://www.epa.gov/iris/subst/0073.htm.*

[54] *See* NAS at page 11 (emphasis added).

actual size of such a group. There are also significant uncertainties concerning the extent to which such exposure might exceed the RfD (an IDI value greater than 1) and whether exposure at such levels would cause adverse effects. *See* TSD. EPA intends to continue to investigate the size and extent to which certain groups might be exposed above the RfD (an IDI value greater than 1), and reserves the right to revisit its risk acceptability determination if future information warrants.

In the meantime, however, given the size of the population, including sensitive subpopulations, that after implementation of CAIR and, independently, CAMR, will be below the RfD (an IDI value of less than 1); the uncertainty of the size and the level to which certain groups may be exposed above the RfD (an IDI value greater than 1); the uncertainties that adverse effects will be experienced by such groups even at levels significantly above the methylmercury RfD (an IDI value greater than 1); and the nature of those potential adverse effects (see TSD), EPA, in its expert judgment, concludes that utility Hg emissions do not pose hazards to public health, and therefore that it is not appropriate to regulate such emissions under section 112.

5. Section 112(f) ''Residual Risk'' Analysis

Some commenters have argued that, in determining whether utility HAPs pose a hazard to public health, EPA is bound to the mandates of section 112(f). In other words, some have argued that unless we can conclude that the imposition of the CAA requirements on utility HAP emissions ''provide[s] an ample margin of safety to protect public health,'' we must regulate utilities under section 112. We disagree. Section 112(n)(1)(A) governs our decision whether to regulate utilities under section 112, not 112(f). Had Congress intended us to apply the same standard, it could have used identical words to those found in section 112(f) or referenced it directly. It did not. Instead, Congress instructed EPA to assess whether utility HAP emissions cause ''hazards to public health.''

Nevertheless, as explained above, in assessing whether remaining utility HAP emissions cause ''hazards to public health,'' EPA used essentially the same analysis that it would use in assessing the human health prong of a 112(f) determination.[55] The factors laid out in the ''benzene'' analysis for assessing acceptable risk to public health under 112(f) are generally relevant to assessing hazard under 112(n)(1)(A). Thus, even if EPA were required to do a 112(f) analysis in determining whether utility Hg emissions pose public health hazards, it is very likely that the conclusion would have been the same, even if the methodology might have been slightly different.

As noted above, section 112(f) expressly incorporates EPA's pre-1990 two-part inquiry for evaluating what level of emission reduction is needed to provide an ample margin of safety to protect public health. See CAA section 112(f)(2)(B) (incorporating EPA's two-part ample margin of safety inquiry, set forth at 54 FR 38044 (Sept. 14, 1989), which implemented the requirements of section 112 of the 1977 CAA). Under this approach, we must first determine what level is ''acceptable'' based exclusively upon the Administrator's determination of the risk to health at a particular emission level. Vinyl Chloride, 824 F.2d at 1164.[56] The Court stressed, however, that ''safe'' in this context does not mean ''risk-free.'' Rather, the Agency must make a determination about what is safe ''based upon an expert judgment with regard to the level of emission that will result in an ''acceptable'' risk to health,'' taking into account the many every day activities that entail health risks but are not considered to be unsafe. *Id.* at 1165.

In this regard, we also note that section 112(f) makes a distinction between pollutants classified as ''known, probable or possible carcinogens'' and other hazardous air pollutants such as Hg. For possible carcinogens, the Agency must set a residual risk standard if ''the individual most exposed to emissions from a source'' is subject to a risk above a certain level. This additional requirement does not apply to other hazardous air pollutants. Therefore, in determining whether any level of Hg emission is 'acceptable' under 112(f), we would use the same basic approach we have used in this case. Although we would evaluate the risk to the maximum exposed individual, which we essentially did for purposes of assessing the hazards posed by utility emissions under section 112(n)(1)(A), we believe that ''the distribution of risks in the exposed population, incidence, the science policy assumption and uncertainties associated with the risk measures, and the weight of evidence that a pollutant is harmful to health are [also] important factors to be considered'' in making a decision as to whether a given level of emissions is acceptable. 54 FR at 38044.

Then, ''[i]n the ample margin decision [the second step], the Agency again considers all of the health risk and other health information considered in the first step. Beyond that information, additional factors relating to the appropriate level of control will also be considered, including costs and economic impacts of controls, technological feasibility, uncertainties, and any other relevant factors.'' 54 FR 38046.

As explained in section H.3. above, applying the general principles articulated in the Vinyl Chloride decision and the benzene rule, the Agency has concluded that power plant Hg emissions remaining after CAIR, and even more so after CAMR, do not pose hazards to public health. This determination was based on health considerations alone, as would be the case under the first step of a 112(f) analysis. Under the second step of a 112(f) analysis, we would then consider both the benefits and costs of further emission reductions. Based on what we know about the uncertainties and nature of the potential adverse effects associated with Hg exposure, the extent to which the public, including sensitive subpopulations, is exposed to Hg, and the extent to which such exposure could be reduced by further reducing Hg emissions from U.S. power plants, we have concluded that the cost of requiring further reductions in Hg emissions from power plants would significantly outweigh any benefits. Therefore, if we were proceeding under section 112(f), we would likely conclude that CAIR, and even more so CAMR, not only protects public health, but does so with an ''ample margin of safety.''

I. The Final CAMR Will Not Lead to Localized ''Utility Hot Spots''

1. What Is a ''Utility Hot Spot''?

As we said in the preamble to the proposed rule, Hg emissions from power plants sometimes are deposited locally near the plant (*i.e.*, within 25 km),

[55] It should be noted that section 112(f) requires consideration of effects on the environment in addition to human health. In contrast, 112(n) requires a narrower assessment.

[56] The Vinyl Chloride court did note, however, that under certain circumstances it might be appropriate to combine the two steps into one. Specifically, the court stated that ''[i]f the Administrator finds that some statistical methodology removes sufficiently the scientific uncertainty present in this case, then the Administrator could conceivably find that a certain statistically determined level of emissions will provide an ample margin of safety. If the Administrator uses this methodology, he cannot consider cost and technological feasibility: these factors are no longer relevant because the Administrator has found another method to provide an 'ample margin' of safety.'' 824 F.2d at 1165, fn 11.

specifically emissions of oxidized and particulate Hg. Nearby waterbodies may be a source of fish consumption for recreational and/or subsistence fishers, and thus local Hg deposition in nearby waterbodies could be a source of what some refer to as ''hot spots.'' In the proposed rule, we suggested 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.'' (*See* 69 FR 4702.)

Based on additional analysis and consideration of the ''hot spot'' issue and to ensure that stakeholders have a common understanding of how EPA uses the term, we define a ''utility hot spot'' as ''a waterbody that is a source of consumable fish with Methylmercury tissue concentrations, attributable solely to utilities, greater than the EPA's Methylmercury water quality criterion of 0.3 mg/kg.'' We believe that the water quality criterion is an appropriate indicator of a ''hot spot,'' given that the Methylmercury exposure pathway of greatest concern is fish consumption and that the water quality criterion was back calculated from the Methylmercury RfD using a high-end fish consumption rate.

2. EPA Does Not Believe That There Will Be Any Hot Spots After Implementation of CAIR and CAMR

As explained elsewhere in this preamble and in the TSD, for purposes of today's notice, EPA modeled utility Hg deposition, before and after implementation of CAIR and CAMR, using the Community Multi-Scale Air Quality (''CMAQ'') model, a three-dimensional eulerian grid model. CMAQ is the most sophisticated Hg dispersion model in existence. It uses a ''one-atmosphere'' approach and addresses the complex physical and chemical interactions known to occur among multiple pollutants in the free atmosphere.[57] The spatial resolution (*i.e.*, the ability to observe concentration or depositional gradients/differences) of the gridded output information from CMAQ for purposes of this analysis is 36 km.

We believe that this an appropriate scale given the exposure pathway. First, because much of the Hg deposited on the watershed of different ecosystems will eventually enter waterbodies through subsurface inflow and runoff, we consider a watershed scale analysis to be more appropriate than finer scale resolution that may only describe direct inputs to surface waters. Second, in larger waterbodies (*i.e.*, the Great Lakes) where there is substantial fishing activity, the higher trophic level fish species consumed by humans are likely migratory and the accumulation of Hg by these species will represent an aggregated signal from deposition over a wider area (*e.g.*, the entire waterbody within a watershed.) Since we are concerned about the cumulative dose over weeks and months from repetitive consumption of fish containing methylmercury, this fishing behavior should be considered in the exposure pathway. Based on the above considerations, we conclude that the HUC–8 watershed is the appropriate unit of measure for analysis. While this analysis covers the vast majority of the U.S. population that may be exposed to emissions from U.S. power plants, we acknowledge that there are inherent uncertainties at the extreme tails of the exposure distribution. We continue to advance the state of the science and the associated models to better understand the tail of this exposure distribution.

As discussed in section VII.D. of today's notice, EPA used fish tissue data from the National Listing of Fish and Wildlife Advisories and the National Fish Tissue Survey to determine Methylmercury fish tissue concentrations for numerous sample sites throughout the country. We then used CMAQ to determine the amount of utility Hg deposition, in conjunction with Mercury Maps (which associates an increment of change in Hg deposition with an equal change in Methylmercury fish tissue concentrations) to predict what fish concentrations at those sample sites would be after implementation of CAIR and CAMR. As discussed in section VII.E., those analyses conclude that none of the sample sites will exceed, as a result of utility emissions, the water quality criterion of 0.3 mg/kg. In fact, our analysis shows that fish tissue Methylmercury concentrations attributable to utility Hg emissions will be significantly below the water quality criterion. By 2020, after CAIR, levels at the 50th, 90th, 99th percentiles and maximum value sample site are predicted to be 0.01, 0.03, 0.10, and 0.25 mg/kg, respectively. After CAMR, levels at the 50th, 90th, 99th percentiles and maximum value sample site are predicted to be 0.01, 0.03, 0.09, and 0.19 mg/kg, respectively. Therefore, based on the information available to us at this time, our analyses indicate utility Hg emissions, after implementation of either CAIR or CAMR, will not result in ''hot spots.''

EPA conducted a similar analysis in its 1998 Utility Report to Congress (''Utility Study'') using the Industrial Source Complex Version 3 (''ISC3'') model. (See TSD) EPA analyzed four model plants representing four utility boilers: Large coal-fired, medium coal-fired, small coal-fired, and medium oil-fired. Each of these plants was also modeled at two generic sites: A humid site east of the 90 degrees west longitude, and a more arid site west of the 90 degree west longitude. (See Utility Study at 7–29). Hg deposition was modeled at a hypothetical lake located at three distances for each model site: 2.5, 10, and 25 km. The results of that analysis showed that under only one modeled scenario was the Methylmercury water quality criterion exceeded. Specifically, the model predicted that a hypothetical lake located 2.5 km from a large eastern coal-fired utility would experience Methylmercury fish tissue concentration of 0.43 mg/kg. None of the other 23 model facilities/lake combinations exceeded the water criterion. (See Utility Study at 7–37).

For a number of reasons more fully explained in our TSD, even though only one facility/lake combination exceeded the water quality criterion, we believe that the analysis done for the 1998 Utility Study was conservative and, hence, over predicted near-field Hg deposition and corresponding fish tissue concentrations in almost all situations. That analysis was a screening analysis and thus was conservative by design. For example, it did not incorporate a sophisticated treatment of the atmospheric chemistry and phase-transition behavior of Hg, as we have included in our CMAQ analysis, and our understanding of wet and dry deposition processes for Hg has improved significantly since then. As a result, we judge that the CMAQ model results represent a more accurate representation of near-field Hg impacts than can be obtained using the ISC3 modeling approach. See the discussion above about why the CMAQ model appropriately represents near-field deposition.

There are other factors that lead EPA to conclude that the Utility Study analysis overstated fish-tissue methylmercury concentrations in most situations. Based on the BAFs considered, the hypothetical ecosystem described in the RTC is more sensitive

[57] In simulating the transport, transformation, and deposition of pollutants, CMAQ resolves 14 vertical layers in the atmosphere, and employs finer-scale resolution near the surface of the boundary layer to simulate deposition to both terrestrial and aquatic ecosystems. CMAQ atmospheric transport is defined using a higher-order meteorological model, commonly the Fifth-Generation Pennsylvania State University/National Center for Atmospheric Research mesoscale model (MM5).

than three out of four ecosystems chosen for the case studies (see Table 4–6, page 25 of Ecosystem Scale Modeling for Mercury Benefits Analysis) and is less sensitive than one (Lake Barco). Comparing these case studies to empirically derived BAFs characterized by the Office of Water indicates that modeled fish tissue responses in three of four case studies had empirically derived BAFs that fell between the 5th and 50th percentiles of the geometric mean of field-measured BAFs for trophic level 4 species obtained from the published literature (EPA 2000). The model ecosystem described in the RTC fell between the 50th and 95th percentile for BAFs, and one of the case studies (Lake Barco) exceeded the 95th percentile.

Some limitations to the BAF approach deserve mention. Because Methylmercury concentrations in the water column are highly variable, empirically-derived BAFs are inherently underdetermined and have limited predictive power. A more credible approach based on our current knowledge is to forecast changes in fish Hg concentrations using information on the food-web dynamics (''bioenergetics'') of different ecosystems. Such a model (BASS) was applied in one of the case studies described in Chapter 3 of the RIA for CAMR, and showed that while the BAFs calculated from the outputs of the bioenergetics-based bioaccumulation model were within a factor of 2 of the empirically derived BAF used in the SERAFM model, the empirically derived fish Hg concentrations were more conservative than the BASS model for this one ecosystem. (See TSD). Thus, the above information suggests that our RTC analysis may have over predicted fish-tissue methylmercury concentrations in many ecosystems that could be impacted by Hg deposition from U.S. power plants. However, it is important to note that fish tissue methylmercury concentrations due to power plants may be higher in some ecosystems (for example, ecosystems similar to Lake Barco described in Ch. 3 of the CAMR RIA).

For all the above described reasons, we think our current modeling approach as described in the TSD provides for a more advanced, state-of-the-science assessment of the atmospheric fate, transport, deposition, and cycling of Hg through the environment than the modeling approach used in the Utility Study. For these reasons, we have no evidence that utility Hg emissions after CAIR (and even more so after CAMR) will result in hot spots.

Based on our experience with the Title IV acid rain program and our modeling using IPM, we believe that the cap-and-trade approaches adopted under CAIR and CAMR will reduce Hg exposure in most areas and create strong economic incentives for the reduction of Hg emissions in the future.

First, modeling runs suggest that large coal-fired utilities contribute more to local Hg deposition than medium-sized and smaller coal-fired utilities.[58] However, under a cap-and-trade system, large utilities are more likely to over-control their emissions and sell resulting emission allowances than smaller utilities, which are less likely to be the source of a local hot spot. Under basic utility economics of capital investment, when capital is limited, up-front capital costs of control equipment are significant, and where emission-removal effectiveness (measured in percentage of removal) is unrelated to plant size, it makes more economic sense for a company to allocate pollution-prevention capital to its larger facilities where more allowances can be earned, than to its smaller ones. In other words, we would expect economies of scale of pollution control investment to be made at larger plants. Moreover, newer plants tend to be larger. Since newer plants have longer expected lifetimes, providing a longer return on investment, we would expect this to be an incentive for these larger facilities to choose to control and sell credits.

Indeed, as part of its analysis of the President's 2003 Clear Skies initiative, EPA analyzed Hg emissions reductions under a cap-and-trade mechanism. In the Clear Skies example, the greatest emissions reductions were projected to occur at the electric generating sources with the highest Hg emissions. This pattern is similar to that observed in the SO_2 emissions trading program under the Acid Rain Program. Under Clear Skies, compared to a base case of existing programs, Hg^{2+} emissions (which tend to be deposited locally, *i.e.*, within 25 kilometers) from power plants located up to 10 kilometers from a water body were projected to decrease by over 60 percent by 2020.

Second, the types of Hg that are deposited locally—Hg^{2+} and Hg_p—are controlled by the same equipment that controls PM, SO_2, and NO_X. Thus, as utilities invest in equipment to comply with EPA's new PM and ozone standards (*e.g.*, the CAIR rule that was signed on March 10, 2005 and new State Implementation Plans (SIPs) for PM and ozone), the Agency expects ''co-benefit'' Hg reductions.

Moreover, EPA's IPM modeling for today's action predicts that larger emitters generally are expected to reduce the most, as was our experience with the Acid Rain Program. Through our CMAQ modeling, we further predict utility-attributable deposition reductions in areas where hotspots would otherwise potentially occur. As described in section VII.E., the median deposition level is reduced by only 8 percent when utilities emissions are zeroed out in 2001, but in areas with the highest deposition levels, zeroing out utilities reduces the 99th percentile deposition level by 15 percent. After implementation of CAIR in 2020, areas with high levels of utility deposition receive a larger reduction in utility-attributable Hg deposition relative to areas with a relatively small level of utility-attributable deposition.

For all these reasons, we do not anticipate that our final CAMR rule will result in local Hg hot spots; to the contrary, we anticipate that our cap-and-trade CAMR will actually eliminate hot spots that may have previously existed.

In addition to reductions required by the CAIR and CAMR caps, states have the authority to address local health-based concerns separate from these programs. Although more stringent state regulations would reduce the flexibility of a cap-and-trade system, states nevertheless have such authority.

3. Continued Evaluation of Utility Hg Emissions

For all the reasons discussed above and elsewhere in this preamble, EPA does not believe that CAIR or CAMR will result in utility-attributable hot spots. That said, we recognize that even our state-of-the-art models and inputs have certain limitations that make it impossible for us to definitively conclude that there are no circumstances under which a hot spot could result even after full implementation of CAIR and CAMR. However, in order for a hot spot to occur, there would have to be an alignment of key environmental factors, such as meteorology, deposition, and ecosystem processes in conjunction with a large uncontrolled near-field utility unit or a collection of such units. The likelihood of these factors converging is remote. Nevertheless, we intend to monitor this situation closely and continue to advance the state of the science of Hg transport and fate. In that

[58] Indeed, the one model utility in the Utility Study analysis that exceeded the water quality criterion at a hypothetical lake within 2.5 km was an eastern large coal-fired utility. Given the tendencies for larger facilities to control under a cap-and-trade system, we do not anticipate that larger plants will cause localized hot spots.

regard, if we receive new information that raises the possibility of utility-attributable hotspots, we will evaluate the situation and take appropriate action.

We believe that we have the authority under the Act to address future hotspots appropriately. Indeed, today we have identified other authorities under the CAA through which we can obtain Hg reductions from coal-fired Utility Units—either by regulating Hg directly, or indirectly as the result of co-benefits. The 1998 Utility Study also identifies other requirements of the Act with which Utility Units must comply that can result in HAP reductions, including Hg. Because we do not currently have any facts before us that would lead us to conclude that utility-attributable hotspots exist, we do not at this time reach any conclusion as to which statutory authority we would use to address such a fact-specific situation because it necessarily depends on the facts.

For example, if in the future we determine that utility-attributable hotspots exist and that those hotspots occur as the result of Hg emissions from coal-fired Utility Units, we may promulgate a tighter section 111 standard of performance, provided we determine the technology can achieve the contemplated reductions. We could revise the standard of performance by adjusting the cap-and-trade program to limit trading by high-emitting Utility Units. As the DC Circuit has recognized, we have discretion to weigh the statutory factors identified in section 111(a), which include cost, in setting a standard of performance. *Lignite Energy Council* v. *EPA*, 198 F.3d 930 (DC Cir. 1999). We therefore believe that under section 111, we can evaluate the cost of emission reduction in the context of the identified hotspots, and we may reasonably conclude that the additional cost of a more stringent standard is appropriate in light of the health concern associated with the hotspots. Alternatively, we may in the future identify utility-attributable hotspots and determine that such hotspots can be addressed by virtue of Hg co-benefits control achieved through the promulgation of other requirements. Thus, although we cannot conclude today which statutory authority we would implement to address utility-attributable hotspots because that determination necessarily hinges on the facts associated with the identified hotspots, we do conclude that were such a situation to occur, we believe that EPA has adequate authority to address any such situation that may arise in the future.

J. The Global Pool of Hg Emissions

1. Background

As explained above, Hg is emitted into the environment in different ways. About one-third of the Hg in the atmosphere is from human-caused activities (''anthropogenic''), one-third is from natural processes (such as volcanic eruption, groundwater seepage and evaporation from the oceans), and one-third constitutes re-emitted emissions, which is Hg from human-caused activities or natural processes that is emitted into the atmosphere, deposited and then re-emitted into the atmosphere. United States anthropogenic Hg emissions are estimated to account for about three percent of the global pool of Hg emissions, and United States (''domestic'') utilities are estimated to account for about one percent of that total global pool. See Utility Study at 7–1 to 7–2, 69 FR at 4657–58 (January 20, 2004). The global pool therefore includes all human-caused activities that occur both within the United States and abroad, all emissions that result from natural processes anywhere in the world, and re-emitted Hg.

To place the Hg emissions from domestic Utility Units in context, EPA modeled different scenarios that analyze the effect of domestic utility Hg emissions in the context of the global pool. We describe that modeling in detail above.

Our modeling shows that in virtually all instances, the utility-attributable methylmercury levels are a very small fraction of the overall methylmercury levels. For 16 percent of the modeled sites, overall levels of methylmercury in fish tissue in 2020 are projected to be above the 0.3 mg/kg water quality criterion. At the 90th percentile, in 2020, after implementation of CAIR, overall levels are projected at 0.79 mg/kg, and at the 99th percentile, at 1.64. The greatest fraction of these methylmercury levels are attributable to non-air sources, including mines and chloralkali plants, and uncontrollable air sources, including international emissions from industrial and utility sources. In virtually all of these instances, the Utility-attributable methylmercury levels are a very small fraction of the overall methylmercury levels. For the highest 10 percent of utility-attributable methylmercury fish tissue levels, utility-attributable methylmercury accounted for a maximum of 9 percent of total methylmercury concentrations, and an average of only 4 percent. Clearly, even at locations with high levels of utility Hg deposition, other sources of Hg contribute most of the methylmercury.

2. Even Examining Utility Hg Emissions in the Context of the Global Pool, We Cannot Conclude That It Is Appropriate to Regulate Coal-Fired Utility Units Under CAA Section 112

Our conclusions in sections VI.J and VI.K above are based solely on our analysis of Hg emissions from coal-fired Utility Units. See generally 65 FR 79,826–29 (explaining that Hg from coal-fired units is the HAP of greatest concern); Utility Study, ES–27 (same). We focused our analysis in this regard because EPA has interpreted section 112(n)(1)(A) to examine the hazards to public health that are ''a result of'' Utility Units. See CAA section 112(n)(1)(A). As explained in section III above, the focus in section 112(n)(1)(A) on emissions ''result[ing]'' from Utility Units is significant, particularly when contrasted against other provisions of the Act, such as section 110(a)(2)(D). In section 110(a)(2)(D), Congress sought to regulate any air pollutant that will ''contribute to'' nonattainment. Thus, under section 110(a)(2)(D), we can regulate a pollutant if it ''contributes'' to a nonattainment problem, but does not itself cause the problem. EPA has concluded that section 112(n)(1)(A) is different, where Congress directed EPA to study the hazards to public health ''reasonably anticipated *to occur as a result of emissions of*'' Utility Units. (emphasis added)

Moreover, Congress' focus on the hazards to public health resulting from Utility Units may reflect Congress' recognition of the unique situation posed by Hg, which is that Hg emissions from domestic utilities represent less than one percent of the global pool. Indeed, Congress specifically addressed Hg in other provisions of section 112(n). For example, under section 112(n)(1)(B), Congress required EPA to complete a study addressing Hg emissions from Utility Units and other sources of Hg. See CAA section 112(n)(1)(B); see also CAA Section 112(n)(1)(C) (requiring National Institute of Environmental Health Sciences to determine the threshold level of Hg exposure below which adverse human health effects are not expected to occur).

Nevertheless, even were we to examine hazards to public health on a broader scale by focusing on the global Hg pool, our conclusion (discussed above in Section IV.A.) that it is not appropriate to regulate coal-fired Utility Units under section 112 on the basis of Hg emissions would be the same. Our analyses in support of that conclusion would differ, however, because we

would be assessing whether it is appropriate to regulate Utility Units under section 112 by reference to a different level of Hg emissions. As explained in section III of this notice, we have discretion, in determining whether regulation under section 112 is appropriate, to consider other factors and, in particular, any unique facts and circumstances associated with the HAP emissions at issue. Here, the unique circumstance is that domestic Utility Units represent only one percent of the global pool. Our modeling shows that were we to prohibit all Hg emissions from domestic utilities in this country, such regulation would result in only a very small improvement in methylmercury levels in the waterbodies that exceed the methylmercury water quality criteria. Therefore, precluding all Hg emissions from coal-fired powerplants would, in effect, force such plants out of business, yet reduce virtually none of the risks to public health stemming from the global Hg pool.

In these circumstances, we find that it is not appropriate to regulate coal-fired Utility Units under section 112 on the basis of the global Hg pool because the health benefits associated with such regulation would be nominal and the costs extreme. It is also not appropriate to regulate Hg emissions from coal-fired utility units remaining after imposition of the requirements of the Act because the global sources contributing most significantly to the remaining public health hazards are not domestic utilities and the sole question before us under section 112(n)(1)(A) is whether it is appropriate to regulate Utility Units under section 112 of the Act.[59]

K. Further Study

The behavior of Hg in the atmosphere and in aquatic systems, and the human health effects of Hg are areas of much interest and activity within the scientific and health research communities. In addition, our ability to quantify and value the effects that changes in Hg releases may have to human health is continuing to evolve. Furthermore, technologies and techniques for limiting Hg emissions from power plants are also rapidly advancing. EPA will continue to monitor developments in all these areas, as well as continuing its own efforts to advance the state of the science. One of the benefits of today's approach is that it provides a flexible structure that could be modified to accommodate new information should it become available.

VII. EPA'S Authority to Regulate HAP From Utility Units Under CAA Section 111

As explained in sections IV and VI above, we conclude today, among other things, that EPA's December 2000 appropriate and necessary finding lacked foundation because it failed to consider the HAP reductions that could be obtained through implementation of section 111, and therefore whether it was ''necessary'' to regulate under section 112. We decide today that it is not ''necessary'' to regulate utility HAPs under section 112, in particular because of our authorities to effectively reduce utility HAPs under CAA sections 110(a)(2)(D) and 111.[60]

We describe below the regulatory scheme under section 111 and EPA's authority to regulate HAP emissions under that section. We also describe the recently issued Clean Air Mercury Rule (''CAMR''), which implements CAA section 111. Finally, we demonstrate that the CAMR rule, once implemented, will result in levels of Hg emissions from coal-fired Utility Units that pose no hazards to public health.

A. Overview of the Requirements of Section 111

CAA section 111 creates a program for the establishment of ''standards of performance.'' A ''standard of performance'' is ''a standard for emissions of air pollutants which reflects 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, any nonair quality health and environmental impacts and energy requirements), the Administrator determines has been adequately demonstrated.'' CAA section 111(a)(1).

For new sources, EPA must first establish a list of stationary source categories, which, the Administrator has determined ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' CAA section 111(b)(1)(A)). EPA must then set federal standards of performance for new sources within each listed source category. (CAA section 111(b)(1)(B)). Like section 112(d) standards, the standards for new sources under section 111(b) apply nationally and are effective upon promulgation. (CAA section 111(b)(1)(B)).

Existing sources are addressed under section 111(d) of the CAA. EPA can issue standards of performance for existing sources in a source category only if it has established standards of performance for new sources in that same category under section 111(b), and only for certain pollutants. (CAA section 111(d)(1)). Section 111(d) authorizes EPA to promulgate standards of performance that states must adopt through a SIP-like process, which requires state rulemaking action followed by review and approval of state plans by EPA. If a state fails to submit a satisfactory plan, EPA has the authority to prescribe a plan for the state. (CAA section 111(d)(2)(A)).

B. EPA's Authority to Regulate HAP Under Section 111

Section 111(b) covers any category of sources that causes or contributes to air pollution that may reasonably be anticipated to endanger public health or welfare and provides EPA authority to regulate new sources of such air pollution. EPA included Utility Units on the section 111(b) list of stationary sources in 1979 and has issued final standards of performance for new Utility Units for pollutants, such as NO_X, PM, and SO_2. See 44 FR 33580; June 11, 1979; Subpart Da of 40 CFR Part 60. Nothing in the language of section 111(b) precludes EPA from issuing additional standards of performance for other pollutants, including HAP, emitted from new Utility Units. Moreover, nothing in section 112(n)(1)(A) suggests that Congress sought to preclude EPA from regulating Utility Units under section 111(b). Indeed, section 112(n)(1)(A)

[59] *See* 36 Cong. Rec. S16895, S16899 (daily ed. Oct. 27, 1990) (Statement of Senator Burdick, member of the Conference Committee and Chairman of the Committee on Environment and Public Works) (''Under section 112(n) utility emissions are exempt from air toxics regulation until studies are completed and the Administrator determines, based on the studies, that air toxics regulation is warranted. The hazardous substance of greatest concern here is Hg. The Senate bill required Hg reductions from coal-fired units. The Senate provision could not be sustained by the scientific facts. What little is known of Hg movement in the biosphere, suggests that its long residence time makes it a long-range transport problem of international or worldwide dimensions. Thus, a full control program in the United States requiring dry scrubbers and baghouses to control Hg emissions from coal-fired power plants would double the costs of acid rain control with no expectation of perceptible improvement in public health in the United States. I am pleased the conferees adopted the House provision on hazardous air pollutants with respect to Utility Units.'')

[60] We also conclude today, as discussed in detail above, that Hg emissions from coal-fired Utility Units remaining after implementation of section 110(a)(2)(D) do not result in hazards to public health. See Sections V and VI. Section 111, which is the focus of this section of the preamble, constitutes an independent basis for our actions today, because that provision, once implemented, will effectively address any Hg emissions from coal-fired Utility Units, and for that reason, Hg emissions from coal-fired Utility Units that remain ''after imposition of the requirements of th[e] Act do not result in hazards to public health.'' CAA Section 112(n)(1)(A).

provides to the contrary, in that it calls for an analysis of utility HAP emissions ''after imposition of the requirements of th[e] Act,'' which we have reasonably interpreted to mean those authorities that EPA reasonably anticipated at the time of the Study would have reduced utility HAP emissions.

EPA received numerous comments concerning its authority under section 111 to regulate HAP from Utility Units. Those comments focused largely on EPA's authority to regulate existing units under section 111(d). As explained below, EPA has reasonably interpreted section 111(d) as providing authority to regulate HAP from existing Utility Units.

Unlike section 111(b), section 111(d) specifically references CAA section 112. The import of that reference is not clear on the face of Public Law 101–549, which is the 1990 amendments to the CAA, because the House and Senate each enacted a different amendment to section 111(d). The Conference Committee never resolved the differences between the two amendments and both were enacted into law as part of section 111(d). EPA is therefore confronted with the highly unusual situation of an enacted bill signed by the President that contains two different and inconsistent amendments to the same statutory provision.

1. Overview of the Two Amendments in Section 111(d)

An important starting point for evaluating the two amendments to section 111(d) in 1990 is the 1977 Act. Section 111(d) of the 1977 CAA provides, in pertinent part:

> 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 7412(b)(1)(A) of this title, but (ii) to which a standard of performance under this section would apply if such existing source were a new source. * * *

42 U.S.C.A. 7411(d) (West 1977); Public Law 95–95. The above language provides that standards of performance under section 111(d) cannot be established for any pollutant that is listed as a ''hazardous air pollutant'' under section 112(b)(1)(A) of the 1977 CAA.

In 1990, Congress significantly amended the CAA. Among other things, it significantly amended section 112, it enacted Title IV of the CAA, which includes numerous provisions that are directly applicable to Utility Units, and it amended section 111(d). Both the House and the Senate bills included different amendments to section 111(d), and both of those amendments were enacted into law.

The first amendment, which is the House amendment, is contained in section 108(g) of Public Law 101–549. That section amends section 111(d)(1)(A)(i) of the 1977 CAA by striking the words ''or 112(b)(1)(A)'' from the 1977 CAA and inserting in its place the following phrase: ''or emitted from a source category which is regulated under section 112.'' The second amendment to section 111(d), which is the Senate amendment, is labeled a ''conforming amendment'' and is set forth in section 302 of Public Law 101–549. That section amends CAA section 111(d)(1) of the 1977 CAA by striking the reference to ''112(b)(1)(A)'' and inserting in its place ''112(b).'' The two amendments are reflected in parentheses in the Statutes at Large 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)* [House amendment,] *(or 112(b))* [Senate Amendment,] but (ii) to which a standard of performance under this section would apply if such existing source were a new source. * * *

The United States Code does not contain the parenthetical reference to the Senate amendment, as set forth in section 302 of Public Law 101–549. The codifier's notes to this section of the Official Committee Print of the executed law state that the Senate amendment ''could not be executed'' because of the other amendment to section 111(d) contained in the same Act. The United States Code does not control here, however. The Statutes at Large constitute the legal evidence of the laws, where, as here, Title 42 of the United States Code, which contains 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). We did not receive any comments disputing either that the Statutes of Large constitute the legal evidence of the laws in this case, or that the 1990 Act contains two different amendments to the same statutory provision.[61]

2. Overview of Legislative History

As we indicated in the proposal, there is scant legislative history concerning the two amendments to section 111(d). The most persuasive legislative history that is relevant to our task of interpreting and reconciling the House and Senate amendments to section 111(d) is the final Senate and House bills. Those bills reflect significantly different treatment of Utility Units under section 112, as well as different amendments to section 111(d).

We begin our analysis with Senate bill 1630, as passed by the Senate on April 3, 1990. That bill included a provision concerning Utility Units. See generally Section 301 (hazardous air pollutants), A Legislative History of the Clean Air Act Amendments of 1990 (''Legislative History''), Vol III, at 4431–33 (Nov. 1993). Under that provision, EPA was to conduct a study on the health and environmental effects of utility HAP emissions within three years of enactment of the statute. The Senate Bill also required EPA to promulgate section 112(d) emissions standards for Utility Units within five years of enactment of the statute. The Senate bill further required EPA to place the study on utility HAP emissions in the docket for the section 112(d) rulemaking for Utility Units. Finally, the Senate bill, in a section labeled ''conforming amendments,'' amended section 111(d) by striking the reference to ''112(b)(1)(A)'' in the 1977 Act and replacing it with ''112(b).'' *See generally* Section 305 (conforming amendments), Legislative History, Vol III, at 4534.

The final bill that passed the House in May 1990 stands in stark contrast to the Senate Bill. The House Bill included section 112(l), entitled ''Electric Utilities.'' *See generally* Section 301 (hazardous air pollutants), Legislative History, Vol II, at 2148–49. That provision is identical to section 112(n)(1)(A). See 104 Stat. 2558. The House bill also amended section 111(d) by replacing the words ''or 112(b)(1)(A)'' with ''or emitted from a source category which is regulated under section 112.'' See Legislative History, Vol. II, at 179.

Finally, the House provision concerning Utility Units is the provision that was enacted into law as section 112(n)(1)(A). The Senate approach to

[61] Although the notes accompanying the Official Committee Print do not interpret with the force of law, their conclusion about the appropriate effect to give these conflicting amendments is evidence that EPA's conclusion is reasonable.

regulating Utility Units under section 112 did not prevail. *See* Legislative History, Vol. I at 1451.

3. EPA's Interpretation of the Two Amendments to Section 111(d)

Neither we, nor commenters, have identified a canon of statutory construction that addresses the specific situation with which we are now faced, which is how to interpret two different amendments to the exact same statutory provision in a final bill that has been signed by the President. The canon of statutory construction that calls for harmonizing conflicting statutory provisions, where possible, and adopting a reading that gives some effect to both provisions is not controlling here because that canon applies where two provisions of a statute are in conflict, not where two amendments to the same statutory provision are in conflict. Nevertheless, we have attempted to follow the general principles underlying this canon of construction. We also rely on the legislative history noted above as support for our interpretation of the two amendments to section 111(d).

Turning first to the House amendment, we noted at proposal that a literal reading of that amendment is that a standard of performance under section 111(d) cannot be established for any air pollutant—HAP and non-HAP—emitted from a source category regulated under section 112. See 69 FR 4685. Certain commenters disagreed with our reading. They argue instead that a literal reading of the House amendment is that EPA cannot regulate under section 111(d) any HAP that is emitted from any source category regulated under section 112. This reading modifies the plain language of section 111(d), as amended by the House in 1990, in significant respects. First, it changes the terms ''any pollutant'' to ''HAP,'' and second, it changes the phrase ''a source category,'' to ''any source category'' and therefore commenters'' reading of the amendment cannot be characterized as a ''literal' reading.

Section 111(d), as amended by the House, specifically provides:

> Each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source *for any air pollutant * * * which is not emitted from a source category which is regulated under section 112.*

We interpret this language to mean that EPA cannot establish a standard of performance under CAA section 111(d) for any ''air pollutant''—including both HAP and non-HAP—that is emitted from a particular source category regulated under section 112. Thus, under our interpretation, if source category X is ''a source category'' regulated under section 112, EPA could not regulate HAP or non-HAP from that source category under section 111(d). This interpretation reflects the distinction drawn in section 111(d), as amended by the House, between ''any pollutant'' and ''a source category.'' The phrase ''any pollutant'' existed prior to the 1990 amendments and therefore it can be reasonably assumed that when the House amended section 111(d) in 1990, it intentionally chose the words ''a source category,'' as opposed to ''any source category. Although we recognize that the phrase ''a source category'' is susceptible to different interpretations, in that it could conceivably mean one or many source categories, we believe that our interpretation is a permissible construction given the juxtaposition of the phrases ''any pollutant'' and ''a source category'' in section 111(d), as amended by the House.

Moreover, consistent with our interpretation of the House amendment, we believe that the House sought to change the focus of section 111(d) by seeking to preclude regulation of those pollutants that are emitted from a particular source category that is actually regulated under section 112. The legislative history described above is instructive in this regard. At the same time the House substantively amended section 111(d), it passed a bill containing a provision (section 112(l)) that is identical to section 112(n)(1)(A) of the current act. Section 112(l) of the House bill calls for EPA to examine how the ''imposition of the requirements of th[e] Act'' would affect utility HAP emissions. This provision suggests that the House did not want to subject Utility Units to duplicative or overlapping regulation. In this regard, the House's amendment to section 111(d) could reasonably reflect its effort to expand EPA's authority under section 111(d) for regulating pollutants emitted from particular source categories that are not being regulated under section 112. Such a reading of the House language would authorize EPA to regulate under section 111(d) existing area sources which EPA determined did not meet the statutory criterion set forth in section 112(c)(3), as well as existing Utility Units (in the event EPA did not decide to regulate such units under section 112).

The Senate amendment provides that a section 111(d) standard of performance cannot be established for any HAP that is listed in section 112(b)(1), regardless of whether the source categories that emit such HAP are actually regulated under section 112. The Senate amendment reflects the Senate's intent to retain the pre-1990 approach of precluding regulation under CAA section 111(d) of any HAP listed under section 112(b). The Senate's intent in this regard is confirmed by the fact that its amendment is labeled a ''conforming amendment,'' which is generally a non-substantive amendment. By contrast, the House amendment is not a conforming amendment.[62]

Moreover, the Senate's conforming amendment is consistent with the Senate's treatment of Utility Units in the final Senate Bill. Unlike the House bill, the Senate bill did not call for an examination of the other requirements of the CAA. Nor did it provide EPA discretion to determine whether Utility Units should be regulated under section 112. Instead, the Senate bill included a provision that would have required EPA to establish section 112(d) emission standards for Utility Units by a date certain. This provision, which was never enacted into law, is consistent with the Senate's conforming amendment which provides that HAP listed under section 112(b) cannot be regulated under section 111(d).

Based on the legislative history described above, we believe that the House amendment, as we have interpreted it, is wholly consistent with section 112(l) of the House bill, which the conference committee adopted as the provision governing Utility Units (section 112(n)(1)(A). It is hard to conceive that Congress would have adopted section 112(n)(1)(A), yet retained the Senate amendment to section 111(d). While it appears that the Senate amendment to section 111(d) is a drafting error and therefore should not be considered, we must attempt to give effect to both the House and Senate amendments, as they are both part of the current law.

The House and Senate amendments conflict in that they provide different standards as to the scope of EPA's authority to regulate under section 111(d). As we explained at proposal, in an effort to give some effect to both amendments, we reasonably interpret the amendments as follows: Where a source category is being regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under section 112(b) that may be emitted from that particular source category. Thus, if EPA is regulating source category X under section 112, section 111(d) could not be

[62] There is a section of the final House bill that includes conforming amendments. The House amendment to section 111(d) does not appear in that sectiono of the bill, however. *See* Legislative History, Vol. II, at 179, 1986.

used to regulate any HAP emissions from that particular source category. This is a reasonable interpretation of the amendments to section 111(d) because it gives some effect to both amendments. First, it gives effect to the Senate's desire to focus on HAP listed under section 112(b), rather than applying the section 111(d) exclusion to non-HAP emitted from a source category regulated under section 112, which a literal reading of the House amendment would do. Second, it gives effect to the House's desire to increase the scope of EPA's authority under section 111(d) and to avoid duplicative regulation of HAP for a particular source category. *See* 136 Cong. Rec. H12911, 12934 (daily ed. Oct. 26, 1990) (the conferees adopted section 112(n)(1)(A) ''because of the logic of basing any decision to regulate on the results of scientific study and because of the emission reductions that will be achieved and the extremely high costs that electric utilities will face under other provisions of the new Clean Air Act amendments.'').

We recognize that our proposed reconciliation of the two conflicting amendments does not give full effect to the House's language, because a literal reading of the House language would mean that EPA could not regulate HAP or non-HAP emitted from a source category regulated under section 112. Such a reading would be inconsistent with the general thrust of the 1990 amendments, which, on balance, reflects Congress' desire to require EPA to regulate more substances, not to eliminate EPA's ability to regulate large categories of pollutants like non-HAP. Furthermore, EPA has historically regulated non-HAP under section 111(d), even where those non-HAP were emitted from a source category actually regulated under section 112. *See, e.g.,* 40 CFR 62.1100 (California State Plan for Control of Fluoride Emissions from Existing Facilities at Phosphate Fertilizer Plants). We do not believe that Congress sought to eliminate regulation for a large category of sources in the 1990 Amendments and our proposed interpretation of the two amendments to section 111(d) avoids this result.[63]

Finally, in assessing whether to revise the December 2000 ''necessary'' finding, it is reasonable to look to whether CAA section 111 constituted a viable alternative authority for regulating utility HAP emissions prior to the December 2000 finding. The answer is yes and therefore under our proposed interpretation of the conflicting amendments, we could have regulated HAP from Utility Units under section 111(d). We listed coal- and oil-fired Utility Units under section 112(c) in December 2000 based solely on our appropriate and necessary finding. As explained above, that finding lacks foundation and recent information confirms that it is neither appropriate nor necessary to regulate Utility Units under CAA section 112. We should have recognized prior to the December 2000 finding that section 111 constituted a viable authority for regulating utility HAP emissions and therefore should have never listed Utility Units on the Section 112(c) list. In addition, as explained below, the December 2000 finding and associated listing is not a final agency action and EPA can therefore make revisions to that finding at any point prior to taking final action. Such revisions are particularly appropriate here, because the prior finding is incorrect and new information confirms this fact.

Some commenters argue that their reading of the House amendment and reconciliation of the amendments is reasonable, but the question is not whether commenters have identified a reasonable construction of section 112(d). Rather, the issue is whether our construction is a permissible one, and for the reasons set forth above, we believe that it is. *See Smiley* v. *Citibank,* N.A. 517 U.S. 735, 744–45 (1996) (a ''permissible'' interpretation is one that is ''reasonable''). Other commenters effectively ask us to ignore the House amendment because the Senate amendment reflects the law as of 1977. We cannot ignore the House amendment, as it is part of current law, and Congress substantially amended the law in 1990, by including, among other things, section 112(n)(1)(A).[64]

VIII. Removal of Coal- and Oil-Fired Utility Units From the Section 112(C) List

Section 112(n)(1)(A) sets forth the criteria for regulating Utility Units under section 112. The criteria are: Whether regulation of Utility Units under section 112 of the CAA is ''appropriate'' and ''necessary.'' In December 2000, EPA added coal- and oil-fired Utility Units to the section 112(c) list in light of its positive appropriate and necessary finding for such units. *See* 65 FR 79831.

In the January 2004 proposed rule, EPA proposed removing coal- and oil-fired Utility Units from the section 112(c) list based on our proposed reversal of the December 2000 finding. Today, we conclude that the December 2000 finding lacked foundation and that regulation of coal- and oil-fired Utility Units under section 112 is not appropriate and necessary. Based on those decisions and our revision of the December 2000 finding, we remove coal- and oil-fired Utility Units from the section 112(c) list. We disagree with those commenters that argue that EPA cannot remove coal and oil-fired Utility Units from the section 112(c) list without satisfying the delisting criteria in section 112(c)(9).

EPA reasonably interprets section 112(n)(1)(A) as providing it authority to remove coal- and oil-fired units from the section 112(c) list at any time that it makes a negative appropriate and necessary finding under the section. Congress set up an entirely different structure and predicate for assessing whether Utility Units should be listed for regulation under section 112. Compare 112(c)(1) and (c)(3), with 112(n)(1)(A). Section 112(n)(1)(A)

[63] The first instance in which the Agency proposed an interpretation of the conflicting House and Senate amendments to CAA section 111(d) was in the January 2004 proposed rule. We recognize that we may have made statements concerning section 111(d), since the 1990 Amendments, but those statements did not recognize or account for the two different amendments to section 111(d), as enacted in 1990. We are also amending 40 CFR 60.21, as part of the final CAMR. That regulation, which was promulgated in 1975, interprets the 1970 CAA and defines a ''designated pollutant'' for purposes of section 111(d), as excluding any pollutant that is listed on the section 112(b)(1)(A) list. There is no section 112(b)(1)(A) in the current act, as amended in 1990. We are therefore revising 40 CFR 60.21 because it does not reflect the current language of section 111(d), as amended in 1990.

[64] Finally, some commenters argue that EPA's interpretation of the conflicting amendments was unreasonable, because it would give EPA discretion to regulate area sources, under section 111, as opposed to section 112. These commenters fail to recognize the listing criteria for area sources under section 112(c)(3). That section, for example, provides that EPA shall list a category or subcategory of area sources under section 112 if it finds that the category or subcategory presents a threat of adverse effects to human health or the environment in a manner ''that warrants regulation under section 112.'' Thus, EPA must determine whether the category or subcategory presents a threat that warrants regulation under section 112. If EPA determined that the listing criteria for a category of area sources were not met, nothing would preclude EPA from regulating HAP from that category under section 111(d), which contains different requirements for regulation. See General Overview of section 111 above.

Another commenter argued that EPA's interpretation of the two amendments is contrary to a canon of statutory construction that provides that where a conflict exists between two provisions of an act, the last provision in point of arrangement controls. This commenter argues that because the Senate conforming amendment is found in section 302 of Public Law 101–549, and the House amendment in section 108(g), the Senate amendment should control. As explained above, this canon of statutory construction is not directly relevant to situations where the conflict at issue is between two different amendments to the same statutory provision. Furthermore, application of this canon of construction would be contrary to the legislative history described above.

therefore occupies the field in section 112 with regard to Utility Units. Section 112(n)(1)(A) provides EPA significant discretion in making the appropriate and necessary finding and nothing in section 112(n)(1)(A) suggests that EPA cannot revise its finding, where, as here, it has both identified errors in its prior finding and determined that the finding lacked foundation, and where EPA has received new information that confirms that it is not appropriate or necessary to regulate coal- and oil-fired Utility Units under section 112.[65]

The section 112(c)(9) criteria also do not apply in two situations that are directly relevant here. First, the December 2000 appropriate and necessary finding and associated listing are not final agency actions. *UARG* v. *EPA,* 2001 WL 936363, No. 01–1074 (DC Cir. July 26, 2001). EPA therefore has inherent authority under the CAA to revise those actions at any time based on either identified errors in the December 2000 finding or on new information that bears upon that finding. Second, as explained in the proposed rule, the section 112(c)(9) criteria do not apply where, as here, the source category at issue did not meet the statutory criteria for listing at the time of listing. See 68 FR 28197, 28200 June 4, 1996; see also 69 FR 4689 (citing additional examples where EPA has removed a source category from the section 112(c) list without following the criteria in section 112(c)(9) due to an error at the time of listing). For all of the reasons noted above, EPA did not meet the statutory listing criteria at the time of listing for coal- and oil-fired Utility Units. Accordingly, coal- and oil-fired Utility Units should never have been listed under section 112(c) and therefore the criteria of section 112(c)(9) do not apply to today's action.

IX. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether a regulatory action is ''significant'' and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

1. Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities;

2. Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

3. Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

4. Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has notified us that it considers this a ''significant regulatory action'' within the meaning of the Executive Order. We have submitted this action to OMB for review. However, EPA has determined that this rulemaking will not have a significant economic impact. Changes made in response to OMB suggestions or recommendations will be documented in the public record. All written comments from OMB to EPA and any written EPA response to any of those comments are included in the docket listed at the beginning of this notice under **ADDRESSES.**

B. Paperwork Reduction Act

This action does not contain any information collection requirements and therefore is not subject to the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*).

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. 104–121) (SBREFA), provides that whenever an agency is required to publish a general notice of rulemaking, it must prepare a regulatory flexibility analysis, unless it certifies that the rule, if promulgated, will not have ''a significant economic impact on a substantial number of small entities.'' 5 U.S.C. 605(b). Small entities include small businesses, small organizations, and small governmental jurisdictions.

As was discussed in the January 30, 2004 NPR, EPA determined that it was not necessary to prepare a regulatory flexibility analysis in conjunction with this rulemaking. We certify that this action will not have a significant impact on a substantial number of small entities because it imposes no regulatory requirements.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) (UMRA), establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under UMRA section 202, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that ''includes any Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more * * * in any one year.'' A ''Federal mandate'' is defined under section 421(6), 2 U.S.C. 658(6), to include a ''Federal intergovernmental mandate'' and a ''Federal private sector mandate.'' A ''Federal intergovernmental mandate,'' in turn, is defined to include a regulation that ''would impose an enforceable duty upon State, local, or Tribal governments,'' section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is ''a condition of Federal assistance,'' section 421(5)(A)(i)(I). A ''Federal private sector mandate'' includes a regulation that ''would impose an enforceable duty upon the private sector,'' with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

We have determined that the final rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, or tribal governments, in the aggregate, or the private sector in any 1 year. Thus, today's final rule is not subject to the requirements of sections 202 and 205 of the UMRA. In addition, we have determined that the final rule contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no regulatory requirements that apply to such governments or impose obligations upon them. Therefore, the final rule is not subject to the requirements of section 203 of UMRA.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the EO to include regulations that have

[65] Although not critical to our analysis, we do note that it is questionable whether we even had a legal obligation in December 2000 to list Utility Units under section 112(c) after making the positive appropriate and necessary finding. Section 112(n)(1)(A) makes no reference to CAA section 112(c) and the framework of section 112(c)(1) and (c)(3) does not expressly provide for the listing of Utility Units. Rather, those provisions speak to major and area sources, which Congress treated differently from Utility Units.

''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. The CAA establishes the relationship between the Federal government and the States, and this rule does not impact that relationship. Thus, EO 13132 does not apply to this rule. However, in the spirit of EO 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on this rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

EO 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.''

This rule does not have Tribal implications as defined by EO 13175. It does not have a substantial direct effect on one or more Indian Tribes, in that it is a determination not to regulate utilities under section 112, and therefore imposes no burdens on tribes. Furthermore, this rule does not affect the relationship or distribution of power and responsibilities between the Federal government and Indian Tribes. The CAA and the Tribal Authority Rule (TAR) establish the relationship of the Federal government and Tribes in implementing the Clean Air Act. Because this rule does not have Tribal implications, EO 13175 does not apply.

Although EO 13175 does not apply to this rule, EPA took several steps to consult with Tribal officials in developing this rule. EPA gave a presentation to a national meeting of the Tribal Environmental Council (NTEC) in April 2001, and encouraged Tribal input at an early stage. EPA then worked with NTEC to find a Tribal representative to participate in the workgroup developing the rule, and included a representative from the Navajo Nation as a member the official workgroup, with a representative from the Campo Band later added as an alternate. In March 2004, EPA provided a briefing for Tribal representatives and the newly formed National Tribal Air Association and NTEC. EPA received comments on this rule from a number of tribes, and has taken those comments and other input from Tribal representatives into consideration in development of this rule.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045, ''Protection of Children from Environmental Health and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be ''economically significant'' as defined under EO 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, section 5–501 of the EO directs the Agency to evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

The final rule is not subject to Executive Order 13045 because it is not an economically significant regulatory action as defined by Executive Order 12866. In addition, EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health and safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulations. The final rule is not subject to Executive Order 13045 because it does not include regulatory requirements based on health or safety risks.

Nonetheless, in making its determination as to whether it is ''appropriate and necessary'' to regulate Utility Units under section 112, EPA considered the effects of utility HAP emissions on both the general population and sensitive subpopulations, including children.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of EO 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of final rulemaking, and notices of final rulemaking: (1) (i) That is a significant regulatory action under EO 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a ''significant energy action.'' Although this final rule is a significant regulatory action under EO 12866, it will not have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; Section 12(d), 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable VCS.

This action does not involve technical standards and therefore the NTTAA does not apply.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898, ''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,'' provides for Federal agencies to consider the impact of programs, policies, and activities on minority populations and low-income populations, including tribes.

As described above, in making its determination as to whether it is ''appropriate and necessary'' to regulate Utility Units under section 112, EPA considered the effects of utility HAP emissions on both the general population and sensitive subpopulations, including subsistence fish-eaters. EPA's analysis considered such subpopulations as the Chippewa in Minnesota, Wisconsin, and Michigan; and the Hmong in Minnesota and

Wisconsin. As explained above, the Agency has concluded that it is not ''appropriate and necessary'' to regulate Utility Units under section 112, in light of all available information, including information on subsistence fish-eaters. The Agency believes that implementation of the CAIR and, independently, the CAMR will remove the hazards to public health resulting from utility HAP emissions.

This action, however, does not actually regulate HAP emissions from utilities. The CAMR does regulate Hg emissions from utilities, and it is in the CAMR rulemaking that EPA has addressed the impacts of that regulation on the populations addressed by Executive Order 12898.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by SBREFA of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the U.S. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the **Federal Register**. The final rule is not a ''major rule'' as defined by 5 U.S.C. 804(2). The final rule will be effective on March 29, 2005.

Dated: March 15, 2005.

Stephen Johnson,

Acting Administrator.

[FR Doc. 05–6037 Filed 3–28–05; 8:45 am]

BILLING CODE 6560–50–P

2007 WL 2155494 (C.A.D.C.) (Appellate Brief)
United States Court of Appeals,
District of Columbia Circuit.

STATE OF NEW JERSEY, et al., Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Respondent.

No. 05-1097 (and consolidated cases) Complex.
July 23, 2007.

On Petition for Review of Final Rules of The United States Environmental Protection Agency
Not Yet Scheduled For Oral Argument

Final Brief of Respondent United States Environmental Protection Agency

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TABLE OF CONTENTS

Note: Pages iv-vi missing in original document.

TABLE OF AUTHORITIES

CASES

Note Pages xi-xii missing in original document.

JURISDICTION

This Court has jurisdiction to review the rules at issue under section 307(b)(1) of the Clean Air Act ("CAA" or "the Act"), 42 U.S.C. § 7607(b)(1).

STATEMENT OF ISSUES

1. Whether EPA may correct an erroneous CAA section 112(n)(1)(A) determination, without applying the criteria set forth in CAA section 112(c)(9)?

2. Whether EPA reasonably determined pursuant to CAA section 112(n)(1)(A), that it is neither "appropriate" nor "necessary" to regulate hazardous air pollutant emissions from coal-fired electric utility steam generating units ("power plants") under CAA section 112?

3. Whether EPA reasonably considered Tribal Petitioners' treaty rights in determining that it is neither appropriate nor necessary to regulate power plant hazardous air pollutant emissions under CAA section 112?

4. Whether EPA has authority under CAA section 111, 42 U.S.C. § 7411, to establish standards of performance for hazardous air pollutant emissions from power plants?

5. Whether EPA in the Clean Air Mercury Rule established appropriate standards of performance under CAA section 111 for mercury emissions from power plants?

STATUTES AND REGULATIONS

Pertinent statutory and regulatory provisions are set forth in the addendum to the brief of State of New Jersey *et al.* ("Government Petitioners"), and to the extent not therein, are set forth in the addendum to this brief. Cited legislative history is in the addendum to this brief.

STATEMENT OF THE CASE

I. NATURE OF THE CASE

These consolidated cases involve challenges to EPA's regulatory program for controlling mercury emissions from power plants. The rules under review include (1) the "Clean Air Mercury Rule" ("CAMR"), 70 Fed. Reg. 28,606 (May 18, 2005), which establishes standards of performance limiting mercury emissions from new and existing power plants, and (2) a final EPA action ("the Section 112(n) Rule"), 70 Fed. Reg. 15,994 (Mar. 29, 2005), that reverses an initial December 2000 finding that it is "appropriate" and "necessary" to regulate power plants under CAA section 112.

CAMR is the first CAA rule ever specifically directed at emissions of mercury from power plants, and when fully implemented, will secure substantial and cost-effective reductions in such emissions. It sets requirements for States to significantly reduce mercury emissions from power plants in two phases and creates a market-based cap-and-trade program that States can use to meet these requirements. New power plants have to meet stringent new source performance standards ("NSPS") in addition to being subject to fixed caps. When fully implemented, CAMR will reduce power plant emissions of mercury from the 1999 level of 48 tons a year to 15 tons a year, a reduction of nearly 70 percent.

The Section 112(n) Rule contains EPA's final determination that it is neither "appropriate" nor "necessary" to regulate power plant emissions under section 112. In making this determination, EPA took into consideration the substantial reductions in mercury emissions from power plants that can and will be obtained under other requirements of the Act, including reductions that will be achieved under CAMR and under EPA's Clean Air Interstate Rule ("CAIR"), 70 Fed. Reg. 25,162 (May 12, 2005).

II. STATUTORY BACKGROUND

The CAA, 42 U.S.C. §§ 7401-7671q, sets up a comprehensive and detailed program for control of air pollution through a system, of shared federal and state responsibility.

A. Regulation of Air Pollutants Under CAA Section 111

Section 111 creates a program for the establishment of "standards of performance." 42 U.S.C. § 7411. A "standard of performance" is "a standard for emissions of air pollutants which reflects 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 non-air quality health and environmental impact and energy requirements) the EPA Administrator determines has been adequately demonstrated." *Id.* § 7411(a)(1).

For new sources, EPA must establish a list of stationary source categories that the Administrator has determined "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." *Id.* '§ 7411(b)(1)(A). EPA must set federal standards of performance for new sources within each listed source category. *Id.* § (b)(1)(B). Section 111(b) standards for new sources apply nationally and are effective upon promulgation. *Id.*

For certain pollutants, section 111(d), 42 U.S.C. § 7411(d), requires EPA to promulgate regulations requiring States to establish standards of performance for existing sources that States must adopt through a process that requires state rulemaking action

followed by review and approval of state plans by EPA. *Id.* If a State does not adopt an approvable plan, EPA is required to promulgate a federal plan implementing standards of performance for that State. 42.U.S.C. § 7411(d)(2).

B. Regulation of Hazardous Air Pollutants Under CAA Section 112

In the 1990 Amendments to the CAA, Congress substantially modified CAA section 112, which addresses hazardous air pollutants.[1] Section 112 provides, among other things, that EPA shall (1) list categories of "major sources"[2] of hazardous air' pollutants, 42 U.S.C. § 7412(c)(1), and (2) subsequently establish pursuant to section 112(d) national emission standards for such sources that "require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section" that the Administrator determines is achievable, taking into account certain factors such as cost, energy requirements, and other impacts. *Id.* § 7412(d)(2). Section 112 further specifies the minimum degree of emissions reductions sources must achieve. *Id.* § 7412(d)(3). Section 112 emission standards are commonly referred to as "maximum achievable control technology" or "MACT" standards.

Although Congress, in amending the Act in 1990, generally mandated that major sources of hazardous air pollutants be regulated under the regulatory program set forth in section 112(d), Congress did not mandate that power plants be subject to this same program. In particular, in CAA section 112(n)(1)(A), 42 U.S.C. § 7412(n)(1)(A), Congress directed EPA not to regulate power plants under section 112 unless EPA first determined that regulation of power plants under section 112 was both "appropriate" and "necessary" after considering public health risks reasonably anticipated to occur as a result of power plants emissions following imposition of other requirements of the Act, such as the standard of performance requirements in section 111. Section 112(n)(1)(A) provides in full as follows:

> 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 chapter. 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 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.

42 U.S.C. § 7412(n)(1)(A).

C. Regulation of Air Pollutants Under CAA Section 110

Pursuant to CAA sections 108 and 109, 42 U.S.C. §§ 7408-7409, EPA has established national ambient air quality standards ("NAAQS") for certain common air pollutants, including ozone and particulate matter. The NAAQS establish permissible concentrations of these pollutants in the "ambient," or outside, air. Pursuant to CAA section 110, States must then establish "State implementation plans" ("SIPs"), which impose controls on individual sources of air pollution as necessary to attain and maintain the NAAQS. 42 U.S.C. § 7410. Section 110 require state rulemaking action followed by review and approval of state plans by EPA at the federal level. If the EPA Administrator finds that an approved SIP is "substantially inadequate" to attain or maintain the NAAQS, mitigate adequately interstate pollutant transport, or otherwise comply with the Act, he is authorized to "require the State to revise the plan as necessary to correct such inadequacies" (a "SIP Call"). *Id.* § 7410(k)(5). CAA section 110(a)(2)(D) requires that SIPs contain provisions prohibiting "any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will ... contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any [NAAQS]." 42 U.S.C. § 7410(a)(2)(D).

III. REGULATORY BACKGROUND

A. The Section 112(n) Rule

Following passage of the 1990 Amendments, EPA conducted a study, pursuant to section 112(n)(1)(A), 42 U.S,C. § 7412(n)(1)(A), to evaluate what hazards to public health, if any, would reasonably be anticipated to occur as a result of emissions of hazardous air pollutants from power plants after imposition of the requirements of the CAA. EPA completed this study on February 24, 1998, and submitted a report to Congress summarizing its results. Docket No. A92-55, Item No. I-A-90 ("the Utility Study") (JA 64-101). After some additional data collection - and without providing an opportunity for notice and comment EPA made a finding, on December 20, 2000, under section 112(n)(1)(A) that regulation of power plants under section 112 was "appropriate and necessary." 65 Fed. Reg. 79,825 (Dec. 20, 2000) ("the December 2000 Finding"). Based on this finding, EPA added power plants to the CAA'section 112(c) list of source categories to be regulated under section 112. *Id.* at 79,831. Petitioner Utility Air Regulatory Group ("UARG") challenged the finding. Applying CAA section 112(e)(4), 42 U.S.C. § 7412(e)(4), this Court held that it lacked jurisdiction to review the December 2000 Finding and that challenges to that finding could be heard only after EPA issued section 112(d) emission standards for power plants. *UARG v.EPA*, No. 01-1074, 2001 WL 936363 (D.C. Cir. July 26, 2001).

On January 30, 2004, EPA issued a proposed role that included two primary alternative regulatory approaches to address mercury emissions from power plants. 69 Fed. Reg. 4652. Under the first approach, EPA proposed retaining its December 2000 Finding and the associated section 112(c) listing of power plants. and issuing final emission standards for power plants under section 112(d). Under the second approach, EPA proposed revising the December 2000 Finding, removing power plants from the section 112(c) list, and issuing standards of performance under section 111.

On March 15, 2005, EPA signed the final Section 112(n) Rule revising the December 2000 Finding based on its final determination that it was, in fact, neither appropriate nor necessary to regulate power plants under CAA section 112. 70 Fed. Reg 15,994 (Mar. 29, 2005). Before taking this final action, EPA received and responded to thousands of public comments and documents, and conducted additional robust air quality modeling and analyses. EPA concluded that it was not "appropriate" to regulate power plants under section 112 because (1) the level of emissions of hazardous air pollutants from power, plants remaining after imposition of other requirements of the Act are not reasonably anticipated to cause hazards to public health, and (2) if EPA were to regulate mercury emissions from power plants under section 112, the costs would be extreme and the health benefits would be nominal, as total domestic power plant emissions are responsible for only a very small fraction of overall mercury levels. 70 Fed. Reg. 16,022/3; 70 Fed. Reg. 16,029/1. In addition, EPA concluded it was not "necessary" to regulate power plants under section 112 because there are other available authorities under the Act that, if implemented, would administratively- and cost-effectively address hazardous air pollutant emissions from power plants. 70 Fed. Reg. 16,005. Based on its revised section 112(n)(1)(A) finding, EPA in the Section 112(n) Rule removed power plants from the section 112(c) list. 70 Fed. Reg. 15,994/2.

On July 8, 2005, environmental group petitioners-moved for a stay of the Section 112(n) Rule pending judicial review. On August 4, 2005, this Court denied Petitioners' request.

B. CAMR

On the same date that he signed the Section 112(n) Rule, the EPA Administrator signed CAMR. 70 Fed. Reg. 28,606 (May 18, 2005). CAMR establishes "standards of performance" pursuant to CAA sections 111(b) and (d) limiting mercury emissions from new and existing power plants.

CAMR creates a standard of performance for existing sources that, when fully implemented, will reduce nationwide annual power plant emissions of mercury from a 1999 baseline of 48 tons to 15 tons. CAMR takes a two-phase approach to achieving mercury reduction. A first phase nation-wide emissions cap of 38 tons per year becomes effective in 2010, and a second phase

cap of 15 tons per year becomes effective in 2018. 70 Fed. Reg. 28,618-19. CAMR sets emission reduction requirements by apportioning emission budgets among the 50 States, two Tribes, and the District of Columbia. *Id.* at 28,623. CAMR further provides States and Tribes with the option of either joining a nationwide emissions cap-and-trade program as a means of implementing required reductions, or achieving required reductions through another method. *Id.* at 28,621.

States that elect to participate in the national cap-and-trade program may allocate emission allowances to individual plants as they deem appropriate as long as the total allocated does not exceed a State's emission budget. *Id.* at 28,632. Under the national cap-and-trade program, individual plants must hold allowances equal to their annual mercury emissions each year. *Id.* at 28,616. Those with allowances in excess of their emissions may sell the excess to other plants or bank the allowances for future use. *Id.* at 28,616, 28,629.

Pursuant to CAA section 111(b), CAMR further requires all new power plants to meet NSPS. CAMR establishes NSPS for five subcategories of power plants: (1) bituminous coal plants, (2) subbituminous coal plants, (3) lignite coal plants, (4) coal-refuse plants, and (5) integrated gasification combined cycle plants. 70 Fed. Reg. 28,612. For subbituminous coal plants, EPA further subcategorized on the basis of water availability. *Id.* at 28,615.

C. The Reconsideration Rule

Following publication of the Section 112(n) Rule and CAMR, EPA received numerous petitions requesting reconsideration of many aspects of the final rules. On October 28, 2005, EPA granted reconsideration on certain issues. 70 Fed. Reg. 62,200; 70. Fed. Reg. 62,213. EPA published its final decision on reconsideration on June 9, 2006. 71 Fed. Reg. 33,388. EPA made two substantive changes to CAMR involving revisions to the state mercury allocations and to the NSPS. EPA reaffirmed its determination that it is neither appropriate nor necessary to regulate power plants under section 112. *Id.* at 33,388-89. EPA conducted, a cost-effectiveness analysis on reconsideration that showed that even assuming a hazard to public health existed from the global pool of mercury emissions, the cost of further reducing mercury emissions under section 112 beyond reductions that will be achieved through other statutory requirements far exceed the health benefits associated with the additional reductions. *Id.* at 33,394.

D. CAIR

Prior to promulgating the Section 112(n) Rule and CAMR, EPA promulgated CAIR, 70 Fed. Reg. 25,162 (May 12, 2005), pursuant to its authority under CAA section 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D).[3] CAIR is intended to address the interstate transport of pollutants that significantly contribute to nonattainment and interfere with maintenance of the ozone and fine particulate matter NAAQS in the eastern United States. In brief, EPA determined that 24 jurisdictions contribute significantly to downwind States' nonattainment of the fine particulate matter standard through emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") and that 26 jurisdictions contribute significantly to downwind States' nonattainment of the ozone standard through emissions of NO_x. 70 Fed. Reg. 25,167. The CAIR emission reduction requirements are based on controls that EPA determined to be highly cost effective for power plants. 70 Fed. Reg. 16,004. CAIR also defines power plant emission budgets for each State that apply if the State chooses to control only power plants. 70 Fed. Reg. 25,167.

The required reductions of SO_2 and NO_x will be implemented in two phases. The first phase of NO_x reductions begins in 2009 and the first phase of SO_2 reductions begins in 2010. The second phase for both SO_2 and NO_x begins in 2015. *Id.* at 25,215-16. Although States may independently determine which emissions sources to control and which control measures to adopt, EPA predicted that most States will regulate power plants and that power plants will comply by installing currently available controls that will reduce mercury emissions as well as NO_x and SO_2 emissions. 70 Fed. Reg. 16,009-10. EPA established guidelines and a model rule for a cap-and-trade program for CAIR in which States may Choose to participate. 70 Fed. Reg. 25,223-25. This program would allow emission credits to be traded by power plants within and between States as a way to reduce the cost of compliance and to provide compliance flexibility.

STANDARD OF REVIEW

Challenged provisions of EPA's rules must be upheld unless they are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 42 U.S.C. § 7607(d)(9)(A). The "arbitrary or capricious" standard is a narrow, deferential standard under which the Court may not substitute its judgment for that of the agency. *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42 (1983). The central issues under this standard are whether the decision "was based on a consideration of the relevant factors and whether there has been a clear error of judgment." *Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402, 416(1971); *Small Refiner Lead Phase-Down TaskForce v. EPA*, 705 F.2d 506, 520-21 (D.C. Cir. 1983).

Questions of statutory interpretation are governed by the two-step test set forth in *Chevron U.S.A. Inc. v. NRDC* ("*Chevron*"), 467 U.S. 837, 842-45 (1984). The reviewing court must first determine "whether Congress has directly spoken to the precise question at issue." *Chevron*, 467 U.S. at 842. If the congressional intent is clear from the statutory language, the inquiry ends. *Id.* at 842-43. If the statute is silent or ambiguous, the reviewing court must determine whether the agency's interpretation is based on a permissible construction of the statute. *Id.* at 843. The Court need not find that EPA's reading is the sole permissible construction, or even that it is the reading the Court would have reached on its own. EPA's interpretation must be upheld as long as it is a reasonable reading of the statute. *Id.* at 843 n.11; *Chemical Mfrs. Ass'n v. NRDC*, 470 U.S. 116, 125 (1985).

Deference is particularly appropriate where, as in this case, the challenged EPA determinations involve complex scientific and technical issues within the special expertise of the agency. *SeeBaltimore Gas & Elec. Co. v. NRDC*, 462 U.S. 87, 103 (1983); *Appalachian Power Co. v. EPA*, 135 F.3d 791, 801-02 (D.C. Cir. 1998) ("Our analysis is guided by the deference traditionally given to agency expertise, particularly when dealing with a statutory scheme as unwieldy and ??

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??plants, and when fully implemented, it will secure significant and cost-effective reductions in such emissions. Contrary to the claims of the Environmental Petitioners (Natural Resources Defense Council *et al.*), CAMR's cap-and-trade system is an appropriate "standard of performance" Under the Act and is consistent with the terms of the statute and applicable judicial precedent. Furthermore, Petitioners' record-based challenges to CAMR are meritless because local and regional variations are an inherent aspect of any standard of performance, and the subcategorization scheme reflected in CAMR was reasonable. Petitioner UARG's claim that CAMR gives States too much discretion has no basis in the statute, and is largely contradicted by applicable precedent of this Court.

Additionally, EPA's mercury emissions allocation to the State of Alaska is supported by the record and consistent with EPA's allocation methodology nationwide. EPA's adjustment factors by coal rank are likewise supported by the record. EPA also correctly calculated the heat content of coal refuse. Petitioner ARIPPA's challenge to EPA'S calculation is based, on partial data and improper application of EPA's methodology.

Accordingly, all of the petitions challenging the Section 112(n) Rule and CAMR should be denied. ??

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?? to power plant regulation, Government Petitioners take the position that EPA only has the authority to make a section 112(n)(1)(A) determination once, and that if the determination is wrong or no longer valid, EPA is powerless to correct its error, no matter how wrong and flawed it may be. *See* Government Br. at 12-14. This position is supported neither by the statutory text nor by principles of administrative law.

In the first place, it is a fundamental principle of administrative law that an agency has inherent authority to reverse an earlier administrative determination or ruling where an agency has a principled basis for doing so. As the Supreme Court stated

in *American Trucking Ass'ns v. Atchison, Topeka & Santa Fe Ry.*, 387 U.S. 397, 416 (1967), an agency "faced with new developments or in light of reconsideration of the relevant facts and its mandate, may alter its past interpretation and overturn past administrative rulings and practice." "[T]his kind of flexibility and adaptability ... is an essential part of the office of a regulatory agency." *Id.* Similarly, the Supreme Court more recently observed:
"An initial agency interpretation is not instantly carved in stone. On the contrary, the agency ... must consider varying interpretations and the wisdom of its policy on a continuing basis," *Chevron, supra* at 863-64, for example, in response to changed factual circumstances, or a change in administrations.

National Cable & Telecomms. Ass'n v. Brand X Internet Servs., 575 U.S. 967, 981 (2005). Likewise, this Court has stated that:

> [A]n agency is free to discard precedents Or practices it no longer believes correct. Indeed, we expect that an [] agency may well change its past practices with advances in knowledge in its given field or as its relevant experience and expertise expands.

Williams Gas Processing Gulf Coast Co. v. FERC, 475 F.3d 319, 326. (D.C. Cir. 2006) (quoting *Nuclear Energy Inst., Inc. v. EPA*, 373 F.3d 1251, 1296 (D.C. Cir. 2004) (per curiam)).

Government Petitioners argue that EPA lacks authority to revise a section 112(n)(1)(A) determination inasmuch as Congress failed to *mandate* periodic review by EPA of a section 112(n)(1)(A) determination, whereas Congress did mandate periodic review of certain other determinations under the Act. *See* Government Br. at 13. Government Petitioners fail to recognize that there is a clear distinction between language that *mandates* periodic EPA review, of some determination, and language that *precludes* review of such a determination. In the absence of any preclusive language, EPA retains its inherent administrative authority to revise a section 112(n)(1)(A) determination where it has a principled basis for doing so. *SeeDun & Bradstreet Corp. Found. v. United States Postal Service*, 946 F.2d 189, 193 (2d Cir. 1991) ("It is widely accepted that an agency may, on its own initiative, reconsider its interim or even its final decisions, regardless of whether the applicable statute and agency regulations expressly provide for such review.") (citation omitted).

2. EPA may revise a section 112(n)(1)(A) determination without applying the delisting criteria in section 112(c)(9).

In section 112(n)(1)(A), Congress directed EPA to regulate power plant emissions under section 112 *only* where it is both appropriate and necessary to do so. Thus, an affirmative section 112(n)(1)(A) determination is a prerequisite to any regulation of power plants under section 112. EPA's express authority in section 112(n)(1)(A) to determine whether power plants should be regulated at all under section 112 necessarily encompasses the authority to remove power plants from the section 112(c) list of source categories to be regulated under section 112 where EPA determines that it has erred in concluding that regulation of power plants is appropriate and necessary or finds that new information has undermined the validity of a previous determination.

Government and Environmental Petitioners take the position that even if EPA is correct that it is, in fact, neither "appropriate" nor "necessary" to regulate power plants under section 112, EPA must nonetheless, as a result of an initial erroneous 112(n)(1)(A) determination, retain power plants on the section 112 list and regulate power plants under section 112. *See* Government Br. at 15-19; Environmental Br. at 14-17. Petitioners contend that EPA can only avoid inappropriate or unnecessary regulation of power plants under section 112 if it makes a different set of findings than set forth in section 112(n)(1)(A) - namely, the findings set forth in section 112(c)(9) required for removing ordinary source categories from the section 112(c) list of categories to be regulated. But this argument ignores the threshold nature of the section 112(n)(1)(A) criteria and stands the statutory framework on its head.

Petitioners contend that their statutory interpretation must be adopted under step one of a *Chevron* analysis. *See* Environmental Br. at 15. Under step one of a *Chevron* analysis, the statute must be construed in its entirety, and the Court cannot confine

itself to reading a particular statutory provision in isolation. *See, e.g.,FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 132(2000)("In determining whether Congress has specifically addressed the question at issue, a reviewing court should not confine itself to examining a particular statutory provision in isolation. The meaning - or ambiguity of - certain words or phrases may only become evident when placed in context."); *Northeast Maryland Waste Disposal Auth. v. EPA*, 358 F.3d 936, 944 (D.C. Cir. 2004) ("As the Supreme Court has instructed, 'the words of a statute must be read in their context and with a view to their place in the overall statutory scheme.' ") (citation omitted).

Reading section 112 in its entirety, it is simply not the case that Congress has unambiguously expressed an intent to compel unnecessary and inappropriate regulation of power plants'. Logically, if EPA makes a determination under section 112(n)(1)(A) that power plants should not be regulated at all under section 112 because it is neither appropriate nor necessary to do so, this determination *ipso facto* must result in removal'of power plants from the section 112(c) list of source categories to be regulated under section 112. To the extent that the section 112(n)(1)(A) criteria and the section 112(c)(9) delisting criteria may be deemed to conflict, the section 112(n)(1)(A) language takes precedence through application of the fundamental rule of statutory construction that "[s]pecific terms prevail over the general in the same ... statute which might otherwise be controlling." *Ginsberg & Sons v. Popkin*, 285 U.S. 204, 208 (1932). Section 112(n)(1)(A) focuses specifically on power plants. Section 112(c)(9) does not.

In short, the intent of Congress is not clear with respect to the applicability of the section 112(c)(9) delisting criteria to power plants. Accordingly, this case cannot be decided under step one of the *Chevron* test, and the Court must proceed ??

Note: Page 27-28

?? pollutants, including mercury, and to establish standards for such sources by November 2000. But, in doing so, Congress made clear that this provision "shall not be construed to require [EPA] to promulgate standards" for power plants. 42 U.S.C. § 7412(c)(6). Accordingly, section 112(c)(6) further underscores that Congress had reservations about regulating power plants under section 112 notwithstanding its recognition that power plants may be a significant source of mercury.

Section 112(c)(3) addresses EPA's listing of "area sources" to be regulated under section 112. Area sources are defined as stationary sources of hazardous air pollutants that are not "major sources." 42 U.S.C. § 7412(a)(2). Environmental Petitioners argue that EPA's interpretation of section 112(n)(1)(A) as allowing it to correct a section 112(n)(1)(A) "appropriate and necessary" determination relating to power plants would also enable EPA to revise section 112(c)(3) area source listing determinations without applying section 112(c)(9) delisting criteria - a result they contend would be "absurd." Environmental Br. at 18. Petitioners are mistaken. Section 112(c)(3) is distinguishable from section 112(n)(1)(A), and the "absurd results" Petitioners contemplate do not actually exist. Congress expressly applied section 112(c)(9) delisting criteria to area sources, but not to power plants. Moreover, Petitioners' section 112(c)(3) argument has been waived because Petitioners failed to raise any concern regarding section 112(c)(3) during the period for public comment. *See* 42 U.S.C. § 7607(d)(7)(B) (providing that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment ... maybe raised during judicial review.").

This Court's decision in *American Methyl Corp. v. EPA*, 749 F.2d 826 (D.C. Cir. 1984), which is cited by Petitioners (*see* Environmental Br. at 18), is also distinguishable. In *American Methyl*, this Court held that EPA could not reconsider a waiver granted under CAA section 211(f), 42 U.S.C. § 7545(f), allowing the sale of a new fuel additive, but had to instead take action under CAA section 211(c), 42 U.S.C. § 7545(c), to prohibit the sale of the fuel additive. CAA sections 211(c) and section 211(f) are not analogous to CAA sections 112(c)(9) and 112(n)(1)(A). First, the Court in *American Methyl* relied heavily on legislative history that expressly set forth Congress' intent that having granted a waiver for a fuel additive under section 211(f), EPA must act to subsequently restrict the sale of such fuel additives through proceedings under section 211(c). *See* 749 F.2d at 834-35. There is no comparable legislative history here indicating Congress intended to preclude EPA from exercising its inherent authority to reconsider a section 112(n)(1)(A) determination. Second, CAA. sections 211(c) and 211(f) address precisely the same thing - fuel additives. By contrast, CAA section 112(n)(1)(A) alone specifically addresses power plants. Third, in section

211(f) Congress placed an express time limitation within which EPA must make a waiver determination, whereas here, Congress did not place any time limitation on making a section 112(n)(1)(A) determination.

Where EPA has determined, as it did here, that it erred in adding power plants to the section 112(c) list in the first place, it is even more apparent that EPA has the authority to correct that initial error and remove power plants from the list of source categories to be regulated without applying the section 112(c)(9) delisting criteria. Indeed, EPA has always interpreted the section 112(c)(9) criteria as inapplicable where the original listing of a source category was inconsistent with statutory listing criteria. *See* 69 Fed. Reg. 4652, 4689 (Jan. 30, 2004) (citing examples where EPA removed a source category from the section 112(c) list without following the criteria in section 112(c)(9) due to an error at the time of listing). For example, in 1992, EPA listed asphalt concrete manufacturers as a major source category under section 112(c)(1), and then in 2002, delisted that source category without following the criteria in section 112(c)(9) because it determined that the initial criteria for listing had not been met. *Id. See* 67 Fed. Reg. 6521, 6522 (Feb. 12, 2002). [5]

Furthermore, the merits of EPA's initial finding have never been subject to judicial review. [6] If EPA cannot correct its own mistake and remove power plants from the section 112(c) list based on its revised section 112(n)(1)(A) finding, this would lead to an anomalous result: that power plants challenging EPA's initial December 2000 determination (when such determination became ripe for review) could obtain relief from this Court - namely, vacatur of the initial section 112(n)(1)(A) determination upon a finding of error - that they could not obtain from EPA, even where the error is conceded by the Agency. EPA should not have to await an adverse ruling from the Court to correct its own mistake. *Cf.Natural Gas Clearinghouse v. FERC,* 965 F.2d 1066, 1073 (D.C. Cir. 1992) (“[A]n agency, like a court; can undo what is wrongfully done by virtue of its [prior] order.”) (citation and quotation marks omitted); *Cleveland Nat'l Air Show, Inc. v. United States Dep't of Transp.*, 430 F.3d 757, 765 (6th Cir. 2005)(“A government agency, like a judge, may correct a mistake, and no principle of administrative law consigns the agency to repeating the mistake into perpetuity.”).

In short, EPA has reasonably concluded that the specific “appropriate” and “necessary” criteria of section 112(n)(1)(A) alone govern whether power plants shall be regulated under Section 112, and that the delisting criteria at section 112(c)(9) do not apply to EPA action under section 112(n)(1)(A).

II. EPA HAS ADOPTED REASONABLE INTERPRETATIONS OF THE TERMS USED IN CAA SECTION 1*l*2(n)(1)(A)

As discussed, above, the condition precedent for regulating power plants under section 112 is a determination by EPA that such regulation is both “appropriate” and “necessary.” The terms “appropriate” and “necessary” are not defined in section 112(n)(1)(A). In the absence of any statutory definition, EPA has reasonably interpreted, these terms consistent with their plain meaning. [7] We set forth EPA's reasonable interpretation of these terms below.

A. EPA Reasonably Interprets the Term “ ‘Appropriate.”

The only guidance in section 112(n)(1)(A) about the substance of EPA's “appropriate” inquiry is that EPA must consider the results of a study identifying “hazards to public health” that are “reasonably anticipated to occur as a result of emissions” of hazardous air pollutants by power plants “after imposition of the requirements of the Act.” 42 U.S.C. § 7412(n)(1)(A).

In view of what Congress directed EPA to consider in the required study, EPA reasonably considers, as a threshold matter, in evaluating whether regulation of power plants under section 112 is “appropriate,” whether “hazards to public health” are “reasonably anticipated to occur as a result of emissions” by power plants “after imposition of the requirements of the [Act].” If such hazards are *not* reasonably anticipated to occur, EPA reasonably concludes that it is not “appropriate” to regulate power plants under section 112. But even if such hazards are reasonably anticipated to occur, EPA reasonably believes other factors

may still make regulation of power plants under section 112 inappropriate. For example, regulation of power plants under Section 112 may not be "appropriate" where the cost of regulation far outweighs the health benefits.

B. EPA Reasonably Interprets the Term "Necessary."

Congress required EPA to determine that it was both appropriate *and* necessary to regulate power plants under section 112. To give Congress' direction full effect, EPA's inquiry into whether it is "necessary" to regulate power plants under section 112 must be distinct from EPA's inquiry into whether it is "appropriate" to do so. Thus, even if EPA determines that it is "appropriate" to regulate power plants under section 112, EPA must also specifically conclude that it is "necessary" to do so.

EPA reasonably concludes that regulation of power plants under section 112 is not "necessary" where there are other authorities under the Act beyond section 112 authorities that, if implemented, would address any hazards to public health posed by power plant hazardous air pollutant emissions in a cost-effective and administratively-effective manner. 70 Fed. Reg. 16,001/2; 71 Fed. Reg. 33,391.

C. EPA Reasonably Interprets The Term "As a Result."

Section 112(n)(1)(A) directs EPA to study "hazards to public health reasonably anticipated to occur as a result of emissions" of hazardous air pollutantss by power plants. 42 U.S.C. § 7412(n)(1)(A). Without considering the context of section 112(n)(1)(A), the "as a result of" phrase might reasonably be read to refer alternatively to either (a) hazards resulting solely from emissions by power plants, or (b) hazards resulting from all sources, including power plants. *Cf.Collinsworth v. AIG Life Ins. Co.*, 404 F. Supp. 2d 911, 920 (N.D. Tex. 2005) (finding phrase "as a result of" appearing in insurance policy was ambiguous and could be read to refer either to actions that are the sole cause of a loss or to actions that are a contributing cause). However, considering the specific context of section 112(n)(1)(A), EPA reasonably construes this phrase as referring to hazards arising solely from power plant emissions.

In section 112(n)(1)(A), Congress distinguished power plants from all other major and area sources of hazardous air pollutants and signaled its reluctance to have power plants automatically subjected to the same stringent regulatory framework as other sources. Congress directed EPA to regulate other major sources of mercury under section 112, but, in sharp contrast, instructed EPA to regulate power plants under that section only if EPA deemed such regulation to be "appropriate and necessary" after studying "hazards to public health reasonably anticipated to occur as a result of emissions by [power plants]." 42 U.S.C. § 7412(n)(1)(A). Congress' unique treatment of power plants provides a strong indication that Congress intended EPA to focus its study under section 112(n)(1)(A) on effects of mercury emissions caused by power plants alone,

Indeed, if Congress had intended to mandate that EPA evaluate all sources of mercury under section 112(n)(1)(A), and that EPA regulate power plants where power plants, made some non-zero contribution to the global pool of mercury, Congress could have simply required regulation of power plants under the same scheme as other sources. Congress already knew at the time of the 1990 Amendments that power, plants were a major source of hazardous air pollutants. Congress further already knew that mercury in the environment generally presented a potential hazard to public health, as reflected by Congress' decision to include mercury on a list of "hazardous air pollutants" and Congress' direction to EPA to establish mercury emission standards under section 112 for all major sources of hazardous air pollutants (but *not* power plants). Interpreting section 112(n)(1)(A) as requiring analysis of whether the *total* amount of mercury in the environment presents some potential health hazard to which power plants make some non-zero contribution renders the section 112(n)(1)(A) inquiry meaningless. *SeeMountain States Tel. & Tel. Co. v. Pueblo of Santa Ana*, 472 U.S. 237, 249 (1985) (noting that it is an ' 'elementary canon of construction that a statute should be interpreted so as not to render one part inoperative' ')(citation omitted).

Furthermore, if Congress had intended EPA to focus its analysis on whether power plants, in combination with mercury emissions from all other sources, contributes to a hazard to public, health, it could have easily made this clear. For example,

Congress could have used language similar to that in section 112(n)(1)(B). In section 112(n)(1)(B), Congress required EPA to study the health effects of mercury emissions from power plants "and other sources." 42 U.S.C. § 7412(n)(1)(B). Congress, however, did not use such language in section 112(n)(1)(A) and did not direct EPA to consider the section 112(n)(1)(B) study in making a section 112(n)(1)(A) determination.

Congress could also have used language similar to that used in CAA section 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D). In section 110(a)(2)(D), Congress required that each SIP contain adequate provisions "prohibiting...any source or other type of emissions activity within the State from emitting any air pollutant in amounts" that will "contribute significantly to nonattainment" of the NAAQS. This language reflects that Congress knew how to specify regulation of emissions of air pollutants even where such pollutants only "contribute" to a problem in combination with other sources. Congress did not use such "contribution" language in section 112(n)(1)(A), and EPA's interpretation of the "as a result of" language in section 112(n)(1)(A) so as to avoid making section 112(n)(1)(A) superfluous is reasonable. *SeeChevron,* 467 U.S. at 843 & n. 11 (holding that where statutory language is ambiguous, EPA's interpretation must be upheld as long as it is a reasonable reading of the statute, and the Court need not find that EPA's reading is the sole permissible construction, or even that it is the reading the Court would have reached on its own). [8]

Environmental Petitioners argue that EPA's interpretation of the phrase "as a result of" cannot be reconciled with EPA's interpretation of the same phrase as it appears in section 112(k)(3)(B), *See* Environmental Br. at 32. This argument is misplaced because the phrase appears in section 112(k)(3)(B) in an entirely different context. In section 112(k), which addresses regulation of area sources, Congress made a specific finding that emissions of hazardous air pollutants from area sources may "individually, or in the *aggregate,* present significant risks human health in urban areas." 42 U.S.C § 7412(k)(1) (emphasis added). Congress. then directed EPA to prepare a comprehensive strategy to reduce aggregate emissions of hazardous air pollutants from area sources in urban areas, including reducing-emissions of the 30 pollutants that "as a result of emissions from area sources" present the greatest threat to public health. 42 U.S.C. § 7412(k)(3)(B). Thus, in section 112(k)(3) Congress made clear that it intended for EPA to prepare a strategy to reduce aggregate emissions from many area sources in urban areas. In sharp contrast, in section 112(n)(1)(A), Congress directed EPA to engage in a very different inquiry - namely, to determine whether it is appropriate and necessary for a particular source Category (power plants) to be regulated under section 112 after regulation of Power plants under other requirements of the Act. Nothing in section 112(k)(3) makes it unreasonable for EPA to focus on power plant emissions exclusively in the context of making a section 112(n)(1)(A) determination. Section 112(n)(1)(A) calls for a different analysis and bears little resemblance to section 112(k)(3).

In short, EPA reasonably focused its "appropriate" analysis on hazards to public health arising solely from power plants.

III. EPA REASONABLY DETERMINED THAT IT IS NEITHER APPROPRIATE NOR NECESSARY TO REGULATE MERCURY EMISSIONS FROM POWER PLANTS UNDER SECTION 112

In the Section 112(n)Rule, EPA reasonably determined that it is neither "appropriate" nor "necessary" to regulate power plants under section 112. We discuss the analyses and reasoning underlying these determinations below.

A. EPA Appropriately Determined. That its December 2000 Finding Lacked Foundation.

In the Section 112(n) Rule, EPA found, as an initial, matter, that its December 2000 Finding was without-foundation. 70 Fed. Reg. 16,002-4. In its December 2000 Finding, EPA failed to fully consider the mercury reductions that would result after imposition of requirements of the Act. EPA's failure to consider these reductions resulted in an overestimate of power plant mercury emissions remaining after imposition of Act requirements. Specifically, EPA explained that it erred in December 2000 by not accounting for the power plant mercury emission reductions that it should have reasonably anticipated would result from implementation of certain other provisions of CAA Title I. 70 Fed. Reg. 16,003/3 First, EPA did not consider mercury reductions that would result from implementation of the revised NAAQS for particulate matter and ozone that EPA issued in July 1997. EPA had recognized in the Utility Study that the revised. NAAQS would result in approximately a 1.6 percent reduction in

mercury emissions, primarily due to the fact that to attain the new particulate matter NAAQS power plants would need to install controls that would also control mercury. *Id.*; Utility Study at 1-2 to 1-3; ES-25, 3-14 (JA 95-96, 89, 99). However, EPA did not consider these reductions in its December 2000 Finding.

Second, EPA did not account in December 2000 for reductions in mercury emissions that would result from two rules controlling NO_x issued pursuant to CAA Title I: (1) a rule ("the NSPS Boiler Rule") setting NSPS under section 111 (b) for NO_x emitted from power plants and industrial boilers, and (2) a rule ("the NO_x SIP call rule") promulgated under CAA section 110(a)(2)(D) requiring 22 States and the District of Columbia to revise their SIPs to mitigate the interstate transport of ozone. 70 Fed. Reg. 16,004/1. Both of these rules were premised on use of a NO_x control technology called selective catalytic reduction. At the time of the December 2000 Finding, EPA had data that confirmed that use of this technology would also result in reductions in power plant mercury emissions, but EPA did not consider these reductions in making its section 112(n)(1)(A) finding. *Id.* [9]

In short, EPA did not take into account in its December 2000 Finding significant reductions in mercury that would result from implementation of Act requirements. Had EPA taken these reductions into account, it believes it would have reached a different conclusion in December 2000. 70 Fed. Reg. 16,003/1. Moreover, as discussed below, new information before the Agency at the time of the Section 112(n) Rule confirmed that EPA had erred.

B. EPA Reasonably Determined That it is Not Appropriate to Regulate Power Plant Mercury Emissions Under Section 112 Because Hazards to Public Health are Not Reasonably Anticipated to Occur As a Result of Power Plant Mercury Emissions Following Implementation of Act Requirements.

Between the time of its December 2000 Finding and promulgation of the Section 112(n) Rule in March 2005, EPA obtained new information concerning mercury emissions from power plants following implementation of Act requirements, and utilizing this new information, conducted sophisticated public health analyses. Based on all of the information before EPA at the time of the Section 112(n) Rule, EPA concluded that the level of mercury remaining after implementation of the requirements of the Act is not reasonably anticipated to pose a hazard to public health, and therefore, it is not appropriate to regulate power plants under section 112. 70 Fed. Reg. 16,004. [10] Accordingly, EPA concluded that its December 2000 Finding should be revised.

In the Section 112(n) Rule EPA considered, among other things, emission reductions that would result from two rulemakings implementing requirements of the Act that had been promulgated subsequent to December 2000: CAIR and CAMR. EPA conducted sophisticated air quality modeling to analyze the nature of mercury emissions from power plants that would remain after implementation of CAIR, and independently, after implementation of CAMR. These analyses demonstrated that the implementation of either CAIR or CAMR alone would result in a level of mercury emissions from power plants that would not cause hazards to public health. 70 Fed. Reg. 16,011-27.

1. Overview of EPA's Hazard Analysis.

In assessing potential hazards to public health from power plant emissions of mercury following implementation of CAIR or CAMR, EPA concluded, as a threshold matter that the predominant pathway of mercury exposure to humans is through the consumption of methylmercury in fish. [11] Domestic power plants emissions contribute to methylmercury in fish, but in virtually all instances, utility-attributable methylmercury levels are a very small fraction of overall methylmercury levels. 70 Fed. Reg. 16,028/2. EPA assessed the risk of methylmercury exposure to individuals resulting from fish consumption and attributable to power plants by considering the concentration of methylmercury in fish that is attributable to power plants (*i.e.*, the "utility-attributable" methylmercury concentration), and the quantity of fish consumed by individuals.

EPA determined that the greatest potential health risk from exposure to utility-attributable mercury is posed to the sub-population of women of child-bearing age who eat self-caught (*i.e.*, noncommercial) freshwater fish. 70 Fed. Reg. 16,011-12. [12]

EPA then rigorously assessed the degree of risk to individuals within this subpopulation employing the following analytical steps. First, EPA used sophisticated modeling to project the location and quantity of mercury deposition from power plants after implementation of CAIR, or independently, CAMR. Second, EPA combined deposition projections with actual freshwater fish tissue data to estimate expected concentrations of utility-attributable methylmercury in fish tissue in particular locations after implementation of CAIR, or independently, CAMR. Third, EPA estimated noncommercial freshwater fish consumption rates. Fourth, EPA compared the degree of exposure to utility-attributable methylmercury from consuming noncommercial freshwater fish to a health-based standard. We summarize each of these analytical steps further below.

a. EPA projected mercury deposition from power plants after implementation of CAIR and CAMR.

EPA used sophisticated state-of-the-art air quality modeling platforms to assess mercury deposition, including deposition attributable to power plants, in particular locations within the contiguous 48 States. 70 Fed. Reg. 16,015-19. EPA's modeling assessed mercury deposition in the baseline year of 2001, and after (a) implementation of CAIR (in 2020), and independently (b) implementation of CAMR (in 2020). *Id.*

EPA applied the Integrated Planning Model("IPM") to project changes in the quantity of future mercury emissions from individual power plants following implementation of CAIR or CAMR in 2020. 70 Fed. Reg. 16,016-17. EPA then applied the Community Multi-Scale Air Quality ("CMAQ") model, which accounts for atmospheric chemistry and meteorology, to assess the amount and location of mercury *deposition* within the contiguous 48 States after implementation of CAIR or CAMR. 70 Fed. Reg. 16,015-16, 16,019. EPA's air quality modeling generally showed that total mercury deposition is not highly impacted by power plants. 70 Fed. Reg. 16,019/3. [13]

b. EPA projected concentrations of utility-attributable methylmercury in fish tissue after implementation of CAIR, or independently, CAMR.

EPA created the largest existing database of actual fish tissue mercury concentrations to measure baseline mercury concentrations in fish tissue in various locations throughout the United States. EPA then combined this fish tissue data with its modeled mercury deposition projections to estimate the concentrations of utility-attributable methylmercury in fish tissue both in the baseline, year of 2001, and after implementation of CAIR or CAMR in 2020, Effectiveness TSD at 19-32 (JA 1891-1904); 70 Fed. Reg. 16,015-21. [14]

EPA estimated fish consumption rates.

EPA estimated noncommercial freshwater fish consumption rates for two broad subpopulations: (1) recreational fishers generally, and (2) individuals, including certain Native Americans, who through choice, socio-cultural practices or necessity consume larger amounts of freshwater fish ("subsistence fishers"). 70 Fed. Reg. 16,021-22; Effectiveness TSD at 33-39 (JA 1905-11). For each of these subpopulations, EPA calculated a range of consumption rates expressed in terms of percentiles. *Id.*

d. EPA compared exposure to the methylmercury Reference Dose.

As the final step, EPA compared the projected exposure to utility-attributable methylmercury to the "Reference Dose" for methylmercury. 70 Fed. Reg. 16,012-13, 16,023-25; Effectiveness TSD at 40-54 (JA 1912-26). [15] In order ??

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?? CAA section 111, 42 U.S.C. § 7411.

Furthermore, EPA's consideration of reductions that will be achieved by CAIR does not undermine any "timeline" established in the 1990 Amendments for regulating hazardous air pollutants from power plants. *See* Environmental Br. at 30-31; Government Br. at 19-20. In the 1990 Amendments, Congress did not establish any deadline at all by which EPA must make a section 112(n)(1)(A) determination, much less establish any deadline by which any regulation of power plants must be fully implemented. To be sure, Congress set a deadline for EPA to complete a study of power plant emissions, but a deadline to complete a *study* is quite different from a deadline to make a regulatory *determination.* Indeed, the terms of section 112(n)(1)(A) indicate that Congress had reasons for setting a study deadline beyond insuring prompt regulation of power plant emissions under section 112 if appropriate and necessary. In particular, it is noteworthy that Congress directed that EPA include in the study and report to Congress on "alternative control strategies for emissions which may warrant regulation under this section." 42 U.S.C. § 7412(n)(1)(A). This indicates that the study deadline may have been intended in part to facilitate Congress' ability to enact some alternative control program for power plant emissions (in place of the section 112 program to which Congress clearly had reservations about subjecting power plants).

In any event, if Congress had intended to set a firm-deadline by which EPA must implement any regulation of hazardous air pollutants from power plants, it could have set one. It did not, and Petitioners attempt to read a timeframe into the Act that is not there. [17]

Furthermore, the 1990 Amendments reflect Congress' recognition generally that Act requirements would take decades to implement and that EPA might need to project emission levels far into the future in making a section 112(n)(1)(A) regulatory determination. For example, Congress enacted the Acid Rain program as part of the 1990 CAA Amendments and provided that this program not be fully implemented until about 2010 - 20 years after enactment of the Amendments. 42 U.S.C. §§ 7651-7651***o***. [18] The 15-year time horizon EPA modeled in the instant Section 112(n) Rule is five years shorter than the 20-year interval between the 1990 Amendments and full implementation of the Acid Rain program. Thus, EPA's consideration of mercury emission reductions that will be achieved by CAIR and CAMR over a 15-year timeframe was consistent with the statutory framework. [19]

a. EPA reasonably calculated mercury reductions that will be achieved by CAIR.

Petitioners additionally contend that EPA should not have relied on reductions in mercury emissions that will be achieved by CAIR because CAIR requires reductions of NO_x and SO_2 but does not specifically require regulation of mercury emissions from power plants. *See* Environmental Br. at 30; Government Br. at 23-24. Although States do have discretion under CAIR to independently determine which sources to control to meet CAIR requirements, this does not mean that EPA is unable to reasonably project how States will control emissions to meet CAIR's requirements. In the final rule preamble and in response to comments, EPA provided a number of compelling reasons as to why it reasonably expects States to implement CAIR by regulating power plant emissions. 70 Fed. Reg. 16,010; Reconsideration RTC at 49 (JA 3750). First, the power sector represents the majority of national SO_2 and NO_x emissions, and EPA analysis found that the most efficient method for States to achieve CAIR SO_2 and NO_x emission reduction targets would be through adoption of controls on the power sector. 70 Fed. Reg. 16,010/2. Second, EPA concluded it is likely that States will choose to implement CAIR in much the same way they chose to implement requirements under a previous similar rulemaking, the "NO_x SIP Call" rulemaking, 63 Fed. Reg. 57,356 (Oct. 27, 1998). *Id.* Under that rulemaking, EPA gave States ozone NO_x reduction requirements, and each State subject to the rulemaking chose to control emissions from power plants to meet NO_x reduction requirements. *Id.*

Petitioners further contend that EPA should not have relied on reductions in mercury emissions that will be achieved by CAIR, because CAIR does not specify the nature of control measures that power plants might adopt to control SO_2 and NO_x emissions, so there is no guarantee that plants would use controls for these pollutants that also reduce mercury. *See* Government Br. at 40; Environmental Br. ??

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?? authority to promulgate CAMR in section V below. However, Petitioners' argument is immaterial with respect to the Section 112(n) Rule because regardless of whether EPA has authority to promulgate CAMR, EPA's health hazard determination would still be sound, based on EPA's projection that utility-attributable mercury emissions that will remain after CAIR alone do not pose a hazard to public health. 70 Fed. Reg. 16,024/3.

2. EPA adequately considered risks posed by local mercury deposition in its health hazard analysis.

While most power plant mercury emissions are deposited far from plants, some mercury emissions are deposited locally (*i.e.*, within 25 kilometers). 70 Fed. Reg. 16,025; Utility Study at ES-18 (JA 82). The CMAQ model used by EPA in its IDI health hazard analysis described above (*see generally*, *supra*, at 44-52) captured elevated localized deposition from power plants. Reconsideration RTC 108 (JA 3791). Moreover, in addition to its IDI analysis, EPA conducted an additional assessment to specifically address whether local deposition of mercury from power plants following CAIR or CAMR would result in ‘ ‘utility hotspots.” *See generally* 70 Fed. Reg. 16,025-28. Contrary to Petitioners' arguments (*see* Environmental Br. at 33-34, Intervenor Physicians' for Social Responsibility (“Physicians' ’) Br. at 11-14), EPA appropriately assessed local deposition both in??

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?? Steubenville Study measured deposition in 2003, and EPA's CMAQ model did not project deposition for that year. 71 Fed. Reg. 33,392-93. The latter is significant because deposition can change significantly from year to year based on both climatological and meterological differences. Reconsideration RTC at144 (JA 3813).

Bearing the above considerations in mind, even using the Steubenville Study as an indirect basis for comparison, the results of the Steubenville Study are consistent with the CMAQ model projections. The Steubenville Study found that approximately 67 percent of mercury depositing at a single hilltop monitor in Steubenville, Ohio, in 2003 was from some form of coal combustion, including power plants. 71 Fed. Reg. 33,392. The CMAQ model similarly predicts for 2001 that power plant coal combustion alone constitutes 44 percent of mercury deposition in the 36-kilometer grid cell including the Steubenville monitoring site. *Id.* One grid cell to the north and three grid cells to the east of the Steubenville monitoring site, the CMAQ model predicts 571 percent and 71 percent deposition from power plant combustion alone respectively. *Id.* Thus, the CMAQ model predicts power plant deposition for the Steubenville area for a different year roughly in the same range as the 67 percent figure measured at the Steubenville monitor from all forms of coal-combustion.

Petitioners further make an invalid comparison (*see* Environmental Br. at 34; Physicians' Br. at 13) when they attempt to compare the Steubenville data to EPA's projections of deposition percentages into entire *watersheds* using CMAQ 36-kilometer grid cell results and other data. By way of background, in its IDI analysis generally, EPA used the CMAQ model, combined with United States Geological Survey (“USGS”) information, to estimate average deposition from power plants at the watershed level. Specifically, EPA used 8-digit hydrological units codes (“HUCs”) developed by USGS to identify watersheds. There are 2,108 distinct 8-digit HUCs in the lower 48 United States, that average approximately 1,631 square miles in size. EPA averaged 36-kilometer CMAQ grid cells within each HUC to generate deposition estimates at the HUC level. 70 Fed. Reg. 16,019/1. It was in the context of assessing power plant mercury deposition percentages in watersheds (*i.e.*, 8-digit HUCs)that EPA noted that, within the *watershed* with the 99th percentile highest total mercury deposition (from all sources, not just power plants), eliminating powerplant emissions would reduce total mercury deposition by 16 percent. 70 Fed. Reg. 16,019/1.

To the extent Petitioners are indirectly contesting EPA's decision to evaluate deposition impacts at the watershed level as part of its IDI analysis, EPA provided sound reasons for doing so. *See* 70-Fed. Reg. 16,026/1-2; Effectiveness TSD at 5 (JA 1877). First, much of the mercury emitted by power plants does not deposit directly into surface waters, but enters waterbodies indirectly through groundwater inflow and runoff at various times of the year. A comprehensive watershed-level analysis better accounts for these entry pathways. *Id.* Second, in larger waterbodies where there is substantial fishing activity, the fish species consumed

by humans are likely migratory, and the accumulation of methylmercury in these fish will come from deposition over a large area. *Id.* Third, many anglers catch fish from a variety of waterbodies in a watershed, and a watershed level analysis better accounts for this fishing pattern. Effectiveness TSD at 5 (JA 1877). [22]

3. EPA reasonably assessed health hazards relating to consumption of fish at subsistence levels.

Tribal Petitioners contend that EPA's freshwater health hazard assessment is defective because EPA allegedly (1) underestimated tribal fish consumption rates and (2) erred in determining that tribal subsistence fishers are unlikely to reside in the areas that will be most significantly impacted by utility-attributable deposition *See* Tribal Br. at 31-42. Tribal Petitioners are wrong on both counts.

a. EPA reasonably estimated subsistence fish

As discussed above, EPA performed a sophisticated modeling analysis to assess exposure to utility-attributable methylmercury through consumption of noncommercial freshwater fish following implementation of CAIR and also of CAMR. EPA recognized in performing this analysis that tribal subsistence fishing populations tend to consume higher levels of freshwater fish than the general population of recreational fishers. EPA therefore distinguished subsistence fishers from the general population, independently assessed subsistence consumption rates, and incorporated different consumption rates for subsistence fishers into its analysis. *See* Effectiveness TSD at 33-39 (JA 1905-11); Reconsideration RTC at 70-77 (JA 3771,78).

The consumption rates EPA applied for subsistence fishers in its modeling analysis were vastly greater than the consumption rates EPA applied for the general population of recreational fishers. Specifically, EPA applied a mean rate of 60 grams of fish per day for subsistence fishers, as opposed to a rate of 8 grams per day for the general population, a 95th percentile rate of 170 grams per day for subsistence fishers, as opposed to a 95th percentile rate of 25 grams per day for the general population, and a 99th percentile rate of 389 grams per day for subsistence fishers, as opposed to a 99th percentile rate of 47 grams per day for the general population. [23]

In estimating subsistence freshwater fish consumption rates for purposes of its analysis, EPA relied upon data from a peer-reviewed study of four Native American tribes located along the Columbia River in Washington, Oregon and Idaho ("the Columbia River Inter-Tribal Fish Commission Study" or "CRITFC Study"). *See* Reconsideration RTC at 72 (JA 3773); CRITFC Study, Legacy Docket: No. A.-92-55, I-H-458 (JA 256) Tribal Petitioners argue that the CRITFC Study data understates subsistence consumption rates and that EPA should have utilized data from other studies, including data from: (1) a study of Tribes located in the Great Lakes region (the "Great Lakes Fish and Wildlife Commission Study," or "the GLIFWC Study"), (2) a study of Tribes in Alaska ("The Alaska Study")(EPA-HQ-OAR 2002-0056-6498.2)(JA 2702), and (3) a study of the Suquamish Tribe in Washington State ("the Suquamish Study") (EPA-HQ-OAR-2002-0056-6498.11) (JA 2730). *See* Tribal-Br. at 33. As discussed below, EPA considered these studies and made a sound decision that the data therein were less suitable for purposes of its modeling analysis than the CRITFC study data. Reconsideration RTC at 72, 191 (JA 3773, 3852)

EPA explained that to be suitable for use in its analysis, fish consumption data needed to meet, among other things, the following three criteria: (1) the data needed to reflect daily consumption rates over an annual period, as opposed to short-term consumption rates, such as a seasonal consumption rate, because the Reference Dose is based on long-term exposure, (2)the data needed to reflect freshwater-sourced fish consumption rates; and (3) the data needed to report consumption rates for identifiable population percentiles (*e.g.,* average 50th percentile consumption rates, and high-end 95th and 99th percentile consumption rates). Effectiveness TSD at 39 (JA 1911); Reconsideration RTC at 72 (JA 3773).

EPA explained that data needed to reflect long-term annual average daily consumption rates because EPA's modeling analysis was premised on assessing long-term exposure to utility-attributable methylmercury and then comparing this long-term exposure to the Reference Dose for methylmercury. *See supra,* at 48-49. The Reference Dose for methylmercury is based

on chronic long-term exposure. Accordingly, long-term annual average consumption data are more relevant and suitable for use than short-term data in a modeling analysis that is intended to compare individuals' exposure to the Reference Dose. Effectiveness TSD at 33 (JA 1905).

EPA further explained that the data needed to reflect freshwater-sourced fish consumption (*i.e.*, fish caught and consumed from rivers and lakes as opposed to estuaries or oceans) because the freshwater fish pathway is the pathway of greatest concern with respect to utility-attributable mercury exposure, and because there is considerable uncertainty associated with extrapolating freshwater fish consumption rates from marine fish consumption rates. Effectiveness TSD at 37 (JA 1909); Reconsideration RTC at 72 (JA 3773).

EPA additionally explained that consumption data needed to include consumption rates for identifiable population percentiles (*e.g.*, average consumption rates and high-end 95th and 99th percentile consumption rates) so that EPA could consider in making a public health hazard assessment the relative number of individuals exposed at particular levels, as opposed to considering only the degree of risk posed to some potentially maximally exposed individual. Effectiveness TSD at 37-38 (JA 1909-10); 70 Fed. Reg. 16,022/3.

Applying the three criteria outlined above, EPA reasonably relied upon the data from the CRITFC Study and not the other studies cited by Petitioners. The CRITFC Study was the optimal dataset before EPA, as it was the only source of data before EPA that met all three required criteria (*i.e.*, it was the only dataset that included annual-average, freshwater fish consumption data for identifiable population percentiles). The GLIFWC Study data did not reflect annual-average consumption rates, and the seasonal consumption rate data within the GLIFWC Study could not be translated into annual-averaged consumption rates without making a number of highly uncertain and speculative assumptions. Effectiveness TSD at 38-39 (JA 1910-11). In addition, the GLIFWC Study did not link consumption data to identifiable population percentiles. *Id.* at 39. The Alaska and Suquamish Studies reported consumption data for coastal tribes that obtained fish from saltwater sources and was not representative of consumption behavior of inland population. Reconsideration RTC at 72 (JA 3773).

Tribal Petitioners contend that even if the CRITFC Study data is probative, the dataset should not have been exclusively relied upon, inasmuch as there is some uncertainty associated with relying on regional data in a nationwide modeling analysis. *See* Tribal Br. at 33-34. The CRITFC Study data, however, comprised the optimal dataset before EPA for use in modeling annualized subsistence consumption rates, and the degree of uncertainty associated with the CRITFC Study dataset was less than the degree of uncertainty associated with alternate datasets available to EPA (*i.e.*, there was less uncertainty associated with using regional data to estimate subsistence consumption rates than with extrapolating annual consumption rates from reported seasonal or saltwater consumption rates). Reconsideration RTC at 72 (JA 3773). [24]

Contrary to Petitioners' suggestion (*see* Tribal Br. at 35), EPA need not invest the resources to conduct a perfect study of subsistence fishing rates. It is a well-established principle of administrative law that where imperfect scientific information is before an agency, the agency may proceed on the basis of imperfect information so long as the agency has a rational basis for doing so. *American Iron & Steel Inst. v. EPA*, 115 F.3d 979, 1004 (D.C. Cir. 1997). Here, the CRITFC Study presented a rigorous peer-reviewed study of annualized freshwater consumption rates by inland subsistence populations and was the optimal dataset before EPA for use in EPA's modeling analysis. EPA has met its minimal burden of demonstrating a rational basis for relying upon the CRITFC Study data in its modeling analysis. *Cf.Dioxin/Organochlorine Ctr v. Clarke*, 57.F.3d 1517, 1524 (9th Cir. 1995)(holding EPA reasonably set limitation on amount of dioxin that could be released into water basin based on projected consumption rate of 6.5 grams per day, notwithstanding evidence before EPA that certain human subpopulations consumed at much greater rates); *NRDC v. EPA*, 16 F.3d 1395, 1403 (4th Cir. 1993) (upholding EPA's approval of State water quality standard for dioxin based on projected consumption rate of 6.5 grams per day, notwithstanding evidence before EPA that tribal subpopulations consumed at greater rates).

Tribal Petitioners additionally contend that EPA should have endeavored to incorporate historical consumption rates into its modeling analysis. *See* Tribal Br. at 36-37. As a practical matter, Tribal Petitioners do not point to any peer-reviewed historical

data in the record that met the required criteria for EPA's modeling analysis described above. But even if such data were to have been in the record, it would still have been reasonable for EPA to rely upon recent data for use in its modeling analysis. Section 112(n)(1)(A) directs EPA to study "hazards to public health reasonably anticipated to occur as a result of emissions" by power plants following implementation of Act requirements and to then make a determination as to whether regulation of power plants under section 112 is "appropriate and necessary." 42 U.S.C. § 7412(n)(1)(A). Even if historical data meeting the required criteria were to have been in the record, EPA could still have reasonably concluded that recent data presents a more accurate picture of hazards reasonably anticipated to occur than older and possibly outdated historical data

b. Tribal Petitioners have waived any challenge to EPA's use of Census Bureau data to identify areas where subsistence populations are likely to reside.

In its freshwater pathway modeling analysis, EPA determined that it is possible that, under certain circumstances, high-end subsistence subpopulations could be exposed to utility-attributable methylmercury concentrations in excess of the Reference Dose following implementation of CAIR and CAMR. In particular, EPA's modeling reflected that, if a subsistence fish consumer were to eat at both a very high subsistence consumption rate and eat solely fish with very high utility-attributable, methylmercury concentrations, that person could be exposed to utility-attributable methylmercury concentrations above the Reference Dose. *See* Reconsideration RTC at Table 2 (JA 3774); Effectiveness TSD at Table 6.4 (JA 1926).[25] EPA concluded, however, that the overwhelming majority of tribal populations live outside of areas most impacted by utility-attributable mercury deposition, and therefore, it was unlikely that a subsistence fish consumer would both eat at a relatively high consumption rate and eat solely fish with relatively high utility-attributable methylmercury concentrations. 71 Fed. Reg. 33,392/3; 70 Fed. Reg. 16,024/1. EPA further explained that at exposures above the Reference Dose, adverse health effects are possible but such exposures do not necessarily mean that adverse effects will occur. 70 Fed. Reg. 16,024/3.

To get a sense of the location of tribal subsistence populations in relation to high utility-attributable deposition, EPA utilized 2000 Census Bureau data. Specifically, EPA mapped the locations of "Tribal Census Tracts," which are defined by the Census Bureau as "relatively permanent statistical subdivisions of a federally recognized American Indian reservation and/or off-reservation Trust land." Effectiveness TSD at 51 (JA 1923). EPA overlaid the locations of Tribal Census Tracts on maps identifying the location of the areas most impacted by utility-attributable mercury deposition following implementation of CAIR. *See* Effectiveness TSD at 52 Figure 6.1 (JA 1924). Visual inspection of the resulting overlay map showed that the overwhelming majority of Tribal Census Tracts would not be within areas most impacted by utility-attributable mercury deposition. *Id.* at 51 (JA 1923).

EPA concluded, based on its comparison of the location of Tribal Census Tracts with the location of areas most impacted by utility-attributable mercury deposition, that "the likelihood that factors will converge such that a [Native American subsistence fisher] would both eat at a high consumption rate and eat solely freshwater fish with high utility-attributable [methylmercury] concentrations is small." 71 Fed. Reg. 33,392. EPA further concluded that although the possibility exists that a very small group of Native American subsistence fishers may be exposed to utility-attributable methylmercury above the Reference Dose, "significant uncertainties exist with respect to the existence and actual size of such a group." 70 Fed. Reg. 16,024-25.

Tribal Petitioners contend for the first time in their brief that EPA erred in using Census Bureau data to identify the general location of tribal subsistence populations. *See* Tribal Br. at 40-42. The contention that EPA erred in using Census Bureau data was not brought to EPA's attention during the rulemaking. *See, e.g.*, EPA-HQ-OAR-2002-0056-6498.1, National Congress of American Indians Comment Letter (JA 2688-2701) (failing to raise any concern with use of Census Bureau data). Accordingly, any argument based on EPA's use of Census Bureau data has been waived. The CAA judicial review provision, 42 U.S.C. § 7607(d)(7)(B), specifically provides that "[o]nly an objection to a role or procedure which was raised with reasonable specificity during the period for public comment ... may be raised during judicial review," and this Court has ' 'strictly' enforce[d]" this statutory requirement. *Mossville Envtl. Action Now v. EPA*, 370 F.3d 1232, 1238 (D.C. Cir. 2004) (citation omitted).

Even if Tribal Petitioners' new argument regarding EPA's use of Census Bureau data could be considered, EPA's use of these data was reasonable. EPA appropriately used these data to approximately identify the location of most subsistence tribal populations. It was not EPA's intent to identify the residence of every Native American in the United States. EPA recognized that subsistence tribal populations are a subset of the general Native American population. Several studies have shown that although Native American anglers generally consume fish at somewhat higher rates than the general population of recreational anglers, they consume fish at rates far lower than rates for Native American subsistence populations. EPA-HQ-OAR-2002-0056-5815, Exposure Factors Handbook at 10-27 (JA 1658); Reconsideration RTC at 191 (JA 3852). In using Tribal Census Tract data, EPA made a reasonable assumption that significant concentrations of tribal subsistence fishing populations reside within Tribal Census Tracts. To the extent that Tribal Petitioners now contend that significant subsistence populations are located outside of formal reservations or trust lands and can be identified through data other than Census Bureau data, they should have brought these concerns to EPA during the public comment period so that EPA could have evaluated these concerns and, if appropriate, incorporated additional information into its analysis, or further explained its decision to continue to rely on Census Bureau data.

4. EPA assessed marine, estuarine, and commercial, fish exposure pathways in its hazard analysis.

Although EPA focused its analysis on risks posed by consumption of fish containing the highest levels of utility-attributable mercury (*i.e.*, noncommercial freshwater fish), EPA's analysis was not limited to this exposure pathway. EPA assessed through additional quantitative and qualitative analyses the degree of risk associated with consuming other kinds of fish, including marine fish, fish caught in estuaries such as the Chesapeake Bay, and commercially-caught freshwater fish. *See generally* 71 Fed. Reg. 33,392-93; Reconsideration TSD at 2-27 (JA 2361-86). Accordingly, Government Petitioners' assertion (*see* Government Br. at 25-26) that EPA did not consider these other pathways is simply wrong.

With respect to marine fish, EPA undertook a thorough and sophisticated quantitative analysis during reconsideration that was similar in depth and scope to the analysis undertaken for the noncommercial freshwater pathway. 71 Fed. Reg. 33,392-93; Reconsideration TSD at 11-16 (JA 2370-75). That analysis, which likely overstated the utility-attributable methylmercury levels in marine fish, showed that the incremental exposure to methylmercury due to power plant emissions from eating marine fish would be less than the Reference Dose, even for a person consuming at the 99.9th percentile rate and consuming exclusively marine fish with high utility-attributable methylmercury concentrations. 71 Fed. Reg. 33,392-93.

Although scientific uncertainties and a lack of data made similar quantitative modeling analyses for other pathways (*e.g.*, commercial freshwater, estuarine, aquaculture) not possible, EPA did engage in detailed *qualitative* analyses with respect to these pathways. *See* Reconsideration TSD at 16-27 (JA 2375-86). These qualitative analyses showed that exposure to utility-attributable mercury through these pathways would be low, and in all cases less than exposure through the noncommercial freshwater pathway. [26]

D. Alternatively, EPA Reasonably Determined That It is Not Appropriate to Regulate Mercury Emissions Because the Costs of Reducing Mercury Emissions Under Section 112 Far Exceed the Benefits.

Beyond finding that regulation of power plants under section 112 is not “appropriate” because hazards to public health are not reasonably anticipated to occur as a result of remaining power plant mercury emissions, EPA concluded alternatively that it is not “appropriate” to regulate power plants under section 112 because the costs of regulating beyond the level that will be achieved by CAIR far exceed the benefits. *See generally*, 70 Fed. Reg. 62,208-09; 71 Fed. Reg. 33,394-95, Reconsideration TSD at 27-38 (JA 2386-87).

For purposes of assessing whether it is cost-effective to regulate mercury emissions under section 112 beyond the level that will be achieved by CAIR, EPA very conservatively assumed a hazard to public health existed resulting from the total “global pool” of mercury emissions. 71 Fed. Reg. 33,394/1; Reconsideration TSD at 29-30 (JA 2388-89). EPA then calculated the upper-bound neurological benefits that would occur from completely *eliminating* domestic mercury emissions from power

plants. Reconsideration TSD at 27-37 (JA 2386-96)[27] EPA concluded that the annualized aggregate upper bound benefit from eliminating mercury emissions from domestic power plants beyond the level that will be achieved by CAIR would be about $210 million. 71 Fed. Reg. 33,394. In contrast, EPA determined that the annualized cost of regulating under section 112 would be at least $750 million.[28] *Id.* EPA's air quality modeling further showed that even if EPA were to prohibit all mercury emissions from domestic power plants, such regulation would result in only a very small improvement in methylmercury levels in waterbodies that exceed the water quality criterion. 70 Fed. Reg. 16,029.

In short, EPA found that the costs of regulation under section 112 far exceed any health benefits that would be obtained. Accordingly, EPA reasonably concluded that it is not "appropriate" to regulate power plant emissions under section 112, even if public health hazards were reasonably anticipated to occur as a result of power plant emissions.

Significantly, no Petitioners have challenged EPA's determination that it is not "appropriate" to regulate power plants under section 112 because to do so would not be cost-effective. Accordingly, even if any of Petitioners' attacks on EPA's public health hazard findings were deemed to have merit, EPA's "appropriate" finding should still be upheld based on EPA's alternative cost-effectiveness rationale.[29]

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?? Congress specifically directed EPA in section 112(n)(1)(A) to focus its determination on whether to regulate power plants under section 112 on a study of health hazards arising from power plant emissions, not consideration of environmental effects. In sum, EPA has properly addressed Tribal Petitioners' issues within the context of Congress' direction in Section 112(n)(1)(A).

A. EPA Adequately Considered Health Effects on Subsistence Fishers.

EPA recognizes that some subpopulations in the United States, including tribal subsistence fishers, consume high levels of fish. 70 Fed. Reg. 16,022. Sophisticated modeling was conducted specifically to analyze the impact of remaining power plant mercury emissions on these subpopulations, and EPA determined that power plant mercury emissions remaining after imposition of the requirements of the Act do not result in a hazard to public health. *Id.* We address EPA's public health analysis, and Tribal Petitioners' criticisms of this analysis, in section III.C.3, above.

B. EPA Appropriately Did Not Consider Fishing Habitats In Its Section 112(n)(1)(A) Analysis.

EPA based its determination that it is not appropriate to regulate power plants under section 112 on its finding that power plant emissions will not result in hazards to public health after implementation of Act requirements. In making this finding, EPA expressly did not consider hazards to the environment generally, including potential impacts on fish habitats where Tribal Petitioners fish. As discussed below, this approach follows Congress' direction and does not violate any established treaty right.

1. Congress directed EPA to consider health effects in CAA section 112(n)(1)(A)

Pursuant to CAA section 112(n)(1)(A), EPA is required 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." 42 U.S.C. § 7412(n)(1)(A)(emphasis added). Furthermore, EPA is required to "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.". *Id.* Thus, when making its "appropriate and necessary" determination, EPA was expressly directed by Congress to consider a study that is limited to public health hazards, not environmental effects.[30] In contrast to section 112(n)(1)(A), other provisions of section 112 expressly require EPA to consider environmental effects. *See, e.g.*, 42 U.S.C. §§ 7412(d)(2), 7412(f). The Supreme Court has recognized that ' '[w]here Congress includes particular

language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally ... in the disparate inclusion or exclusion.' '. *Russello v. United States*, 464 U.S. 16, 23 (1983)(citation omitted).

Tribal Petitioners make a *Chevron* step one argument, claiming that EPA's decision not to consider environmental effects insofar as they relate to the United States' treaty obligations disregarded the unambiguously expressed intent of Congress. Tribal Br. at 23-24. Congress, however, did not unambiguously require EPA to consider *any* environmental effects at all in section 112(n)(1)(A). Instead, Congress required EPA to consider a study that was limited to the health effects of power plant emissions. 42 U.S.C. § 7412(n)(1)(A). In short, *Chevron* step one does not require EPA to consider potential treaty rights of Tribal Petitioners insofar as they relate to environmental effects. *See Chevron*, 467 U.S. at 842.

2. No treaty right to habitat protection has been established.

EPA reasonably declined to premise its section 112(n)(1)(A) determination on consideration of environmental effects, including potential treaty rights of Tribal Petitioners insofar as they are alleged to encompass a right to habitat ??

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?? *FAA*, 161 F.3d 569, 574 (9th Cir. 1998), "although the United States does owe a general trust responsibility to Indian tribes, unless there is a specific duty that has been placed on the government with respect to Indians, this responsibility is discharged by the agency's compliance with general regulations and statutes not specifically aimed at protecting Indian tribes."

The Tribal Petitioners cite *Northwest Sea Farms, Inc. v. United States Army Corps of Engineer*, 931 F. Supp. 1515 (W.D. Wash. 1996); *Muckleshoot Indian Tribe v. Hall*, 698 F. Supp. 1504 (W.D. Wash. 1988); and *Confederated Tribes of the Umatilla Indian Reservation v. Alexander*, 440 F. Supp. 553 (D. Or. 1977), for the proposition that the United States must take tribal treaty rights into account when taking action that potentially affects them. Tribal Br. at 26. None of these decisions, however, expressly recognizes a treaty-based right to habitat protection, much less one that would extend to an EPA determination under CAA section 112(n)(1)(A). Thus, although the United States owes a general trust responsibility to Tribal Petitioners, that duty has been discharged by EPA's compliance with Congress' direction in section 112(n)(1)(A)to consider hazards to public health anticipated to occur as a result of power plant emissions. Section 112(n)(1)(A) does not entitle Tribal Petitioners to a greater degree of environmental protection than Congress provided to citizens generally.

Moreover, Tribal Petitioners' argument assumes that at least some of their member Tribes, through various treaties with the United States, have both a right to fish and a right to habitat protection for certain fisheries. Tribal Petitioners, however, fail to demonstrate that any such right to habitat protection for certain fisheries has either been expressly provided for in the treaties they cite, or has been recognized in case law. The treaties are not facially clear on this issue, and the United States is unaware of any federal or state court decisions currently. recognizing tribal rights to habitat protection.

In general, tribal fishing rights entitle tribes to "take a fair share of the available fish." *Washington v. Washington State Commercial Passenger Fishing Vessel Ass'n*, 443 U.S. 658, 684-85 (1979) ("*Fishing Vessel*"). According to the Supreme Court's interpretation of a series of treaties protecting tribal fishing rights in western Washington, a "fair share" allows Indians to secure as much as 50 percent of a fishing harvest, "but no more than is necessary to provide the Indians with a livelihood - that is to say, a moderate living." *Id.* at 686. Thus, *Fishing Vessel* and other cases cited by Tribal Petitioners support the proposition that treaties do create an enforceable right for protected tribes to take fish throughout their fishing areas. The cited case does not, however, create a right to habitat protection.

The United States is not aware of any decision that currently acknowledges a right to habitat protection stemming from tribal treaty rights. *SeeSkokomish Indian Tribe v. United States*, 410 F.3d 506, 522, n.2 (9th Cir. 2005) (noting that the Ninth Circuit, in a subsequently vacated decision, once addressed the "challenging question ... whether the Tribe's off-reservation fishing rights give rise to a cause of action for limiting the numbers of fish that formerly inhabited the streams and rivers in which

the Tribe traditionally fished, or whether, instead, the Treaty preserves only a right to take a given proportion of such fish as remain extant.") (Berzon, J., dissenting in part), *cert. denied*, 126 S. Ct. 1025 (2006); *United States v. Washington*, 694 F.2d 1374 (9th Cir. 1982), on *en banc* reh'g, 759 F.2d 1353, 1355 (9th Cir. 1985) (failing to determine whether "the right to take fish necessarily includes the right to have those fish protected from man-made despoliation"); *Nez Perce Tribe v. Idaho Power Co.*, 847 F. Supp. 791, 810 (D. Idaho 1994) (holding that a Northwest Indian treaty "does not provide a guarantee that there will be no decline in the amount of fish available to take"); *Cohen's Handbook of Federal Indian Law* 1140 (Nell Jessup Newton et al., 3d ed. 2005) ("Courts have not yet definitively determined whether off-reservation reserved right include the right to habitat protection for the species subject to the rights."). The "habitat 'protection" question was extensively briefed, during the decades-long history of the *United States v. Washington* series of cases. In *United States v. Washington*, 506 F. Supp. 187, 202-03 (D.C. Wash. 1980), a district court found that a right to "habitat protection" exists. This decision was initially affirmed on other grounds, *United v. Washington*, 694 F.2d 1374, 1381 (9th Cir, 1982), but ultimately was overturned after *en banc* review, *United States v. Washington*, 759 F.2d 1353, 1357 (9th Cir. 1985) *(en banc)* (finding that legal standards governing the interpretation of the treaty rights are factually dependent, the consequences, of making the "habitat rights" determination were unknown, and announcing imprecise legal roles through the declaratory judgment procedure was inappropriate).

3. Congress' specific direction in section 112(n)(1)(A) that EPA should consider health effects trumps undefined treaty rights.

Where there is no clear intention to the contrary,' a specific statute will not be controlled or nullified by a general one. *Morton v. Mancari*, 417 U.S. 535, 550-51 (1974). This rule of construction applies equally when determining whether a specific statutory regime trumps the general concepts set forth in a treaty, as treaties are in full parity with Acts of Congress. *SeeReid v. Covert*, 354 U.S. 1, 18 (1957)(plurality opinion); *Whitney v. Robertson*, 124 U.S. 190, 194 (1888) ("By the constitution, a treaty is placed on the same footing, and made of like obligation, with an act of legislation."). As discussed above, the treaties relied upon by Tribal Petitioners do not expressly create a right to habitat protection, and such a right has not been judicially articulated. By contrast, section 112(n)(1)(A) specifically addresses how EPA should go about determining whether to regulate hazardous air pollutant emissions from power plants under section 112. Consistent with Congress' specific direction in section 112(n)(1)(A), EPA appropriately focused on public health effects in making its "appropriate and necessary" determination, and not on environmental effects.

4. EPA lacked a sufficient record to properly determine whether a treaty-based habitat right to protection of tribal fisheries right exists, much less to consider the effect of that determination on the Section 112(n) Rule.

Given that treaties do not facially provide a fight to habitat protection and such a right has not been judicially established, it would have been inappropriate for EPA to itself opine on the existence of, and extend its CAA analysis to consider, such an ill-defined, controversial, and complex "right." Instead, EPA appropriately addressed Tribal Petitioners' concerns by complying with Congress' direction in CAA section 112(n)(1)(A).

Indeed, taken to its logical extension, Tribal Petitioners' position would require EPA to have determined in the first instance, upon making a section 112(n)(1)(A) determination, whether any right to "habitat protection" was conveyed along with fishing rights when the United States entered into hundreds of treaties with numerous Tribes in the course of the history of this Nation. EPA would further have had to consider the extent of any such right to habitat protection. EPA does not have the expertise to make such complex determinations, Nor did EPA have the record before it to make such determinations.

Unlike statutory interpretation, where one party's (Congress') intent is expressed in congressional reports, floor debate, and other legislative history, interpretation of tribal treaties must take place in a complex historical framework, frequently requiring the aid of extensive factual evidence. *SeeUnited States v. Washington*, 384 F. Supp. 312, 348, 350 (W.D. Wash. 1974) (reviewing statements of "nearly 50 witnesses, whose testimony was reported in 4,600 pages of trial transcript, more than 350 exhibits, pre-trial briefs, final oral argument 12/9-10/73 and post trial briefs" to determine both the Tribes' "usual and accustomed" fishing

places and to interpret relevant treaty language), *aff'd*, 520 F.2d 676 (9th Cir. 1975), *cert. denied*, 423 U.S. 1086 (1976)). Tribal treaties must be construed as they were understood by the Tribes at the time they were negotiated. *Jones v. Meehan* 175 U.S. 1, 11 (1899). Although analysis of treaties begins with the text of the treaty, it does not necessarily end there: "[t]reaties are construed more liberally than private agreements, and to ascertain their meaning we may look beyond written words to the history of the treaty, the negotiations, and the practical construction adopted by the parties." *United States v. Washington*, 135 F.2d 618, 630 (9th Cir. 1998), *superceded by* 157 F.3d 630, 642-43 (9th Cir. 1988) (citation omitted).

Here, Tribal Petitioners, whose comments obliquely claimed treaty rights, did not proffer expert opinion for EPA's review or submit any of the extensive documentation typically presented to district courts in treaty cases. By neglecting any examination of the United States' intent going into the referenced treaties and the United States' understanding of their terms, as well as any comprehensive and necessary examination of the intent and understanding of the Tribes, Tribal Petitioners ask EPA and this Court to reach sweeping and unprecedented conclusions in the absence of an adequate record. The fact that the *United States v. Washington* litigation is continuing after more than two decades, and that the alleged tribal rights to "habitat protection" have not yet been resolved for the narrow set of treaties involved in those cases, underscores the complexity underlying the "habitat protection" question.

In short, in the absence of an adequate record and expertise on issues of treaty interpretation, it would have been inappropriate, for EPA to have based its Section 112(n)(1)(A) determination on the Tribes' conclusory and sweeping assertions that a treaty-based right to habitat protection, exists. In the absence of an adequate record, it would be equally inappropriate for this Court to address on judicial review whether any treaty-based right to habitat protection exists. *See* CAA section 307(d)(7)(A) (limiting judicial review, to record before agency). The issue of habitat protection is very complex, has tremendous potential consequences, and, not surprisingly, has resulted in considerable litigation, including lawsuits involving numerous tribes, States, and other parties that have been pending for years. Eventually, in a proper setting in which the many nuances of treaty language and construction can be examined, one or more sufficiently clear judicial determinations as to whether such a right exists and, if so, how it can or should be applied, will emerge. This, however, is neither the right time nor the right place for such a complex issue to be resolved.

V. EPA HAS AUTHORITY UNDER CAA SECTION 111 TO ESTABLISH STANDARDS OF PERFORMANCE FOR MERCURY EMISSIONS FROM POWER PLANTS

A. Introduction

CAA section 111, 42 U.S.C. § 7411, the section under which EPA promulgated CAMR, calls for EPA to establish, subject to certain, limitations, standards of performance for new and existing sources of air pollution that may reasonably be anticipated to endanger public health or welfare. The first question EPA had to answer in adopting CAMR was whether any of the limitations in section 111 precluded the Agency from establishing standards of performance for mercury emissions from power plants. As EPA noted, nothing in the statute bars the adoption of section 111 standards of performance for *new* sources of hazardous air pollutants, *see* 70 Fed. Reg. 16,029, and Petitioners do not contend otherwise. However, EPA also acknowledged that this question is more complicated as it pertains to *existing* sources.

As EPA explained in the Federal Register notice announcing the revised section 112 finding, prior to 1990 CAA section 111(d)(1), 42 U.S.C. § 7411(d)(1), expressly barred existing source standards of performance for any hazardous air pollutant listed pursuant to the process set forth in then-existing CAA section 112(b)(1)(A).[31] However, when Congress extensively revised the hazardous air pollutant provisions in section 112 in 1990 (which included the elimination of former section 112(b)(1)(A) and the addition of section 112(n)(1)(A)), it also made corresponding changes to this portion of section 111 (d). Apparently as a result Of the rash toward final passage of the amendments, the version signed into law by the President actually contained two different amendments to section 111(d) - one version from the Senate bill and one version from the House bill - that were never reconciled in conference. Although the House version of this provision is the one that is set forth in the United States

Code, both versions were included in the Statutes at Large (Public Law No. 101-549), and in the circumstances presented here, it is the Statutes at Large that controls. [32]

Section 302(a) of Public Law No. 101-549 contained the Senate's amendment to CAA Section 111(d), and it simply provided that the former cross-reference to the list of hazardous air pollutants in section "112(b)(1)(A)" be changed to section "112(b)" *See* Pub. L. No. 101-549, § 302(a), 104 Stat. 2574 (1990). In contrast, section 108(g) of Public Law No. 101-549, which contained the House amendment, provided that section 111(d)'s reference to section "112(b)(1)(A)" be replaced with the phrase "or emitted from a source category which is regulated under section 112," *See* Pub. L. No. 101-549, § 108(g), 104 Stat. 2467 (1990). Putting all this together, then, after the 1990 Amendments, the pertinent portion of CAA section 111(d) provided for the establishment of standards of performance for existing sources for any air pollutant which (under the Senate version) is "not included on a list published under section ... 112(b)," or which (under the House version) is not "emitted from a source category which is regulated under section 112."

Both the Environmental and Government Petitioners generally argue that any differences between the House and Senate amendments to section 111(d) are insignificant, that neither House of Congress intended to make any substantive change to section 111(d) in 1990, and that EPA, therefore, still may not regulate under section 111 emissions of any hazardous air pollutant listed under section 112. *See* Environmental Br. at 20-24; Government Br. at 27-29. EPA disagrees. The 1990 Amendments to section 111(d) presented EPA with the difficult and unique situation of interpreting two conflicting versions of the same statutory provision. In light of this difficulty, EPA reasonably concluded that the 1990 Amendments to section 111(d) allowed the Agency to establish existing source standards of performance for emissions of any hazardous air pollutant from a source category that is not regulated under section 112. As will be explained below, the Agency's interpretation represents a reasonable harmonization of the conflicting House and Senate provisions that should be upheld under *Chevron* and other applicable judicial guidance.

B. EPA's Approach Harmonizes the Conflicting Amendments to Section 111(d)and Reflects A Reasonable Interpretation of the Statute.

This Court confronted a similar statutory issue in *Citizens to Save Spencer County v. EPA*, 600 F.2d 844 (D.C. Cir. 1979), a case considering conflicting provisions in the 1977 Amendments to the Act. One of these provisions appeared to *bar* certain new construction until EPA issued new regulations under the 1977 Amendments while another provision appeared to *allow* such construction pursuant to the requirements of EPA's prior regulations until the new regulations came out. *Id.* at 853-54. The Court considered and rejected a variety of arguments posited by environmental and industry petitioners in support of conflicting all-or-nothing interpretations of these provisions, *id.* at 860-72, and instead endorsed EPA's attempt to "devise a middle course between inconsistent statutes so as-to give maximum possible effect to both" *Id.* at 872. In denying the petitions for review, the Court concluded that although "[o]ther, equally reasonable: accommodations of the above competing interests can be imagined," it would defer to EPA's "attempt to bring harmony and efficiency to a regulatory scheme that in its original statutory conception was badly flawed." *Id.* at 890.

The Court's guidance in *Spencer County* is pertinent here, both because of the factual similarity between that case and this and because the Court's deferential approach to agency constructions of statutes they are charged with implementing has since been strongly reinforced by the Supreme Court's decisions in *Chevron*, *Mead*, and related cases. [33] As will be discussed below, a careful review of the statute shows that there is a real and meaningful conflict between the text of the House and Senate amendments to section 111(d), that the foundation for this conflict is evidenced in the legislative history of the 1990 Amendments, and that EPA's interpretation represents a reasonable attempt to harmonize these conflicting provisions.

1. EPA reasonably read the text of the House and Senate amendments to section 111(d) to conflict.

EPA began its statutory analysis with the text of the two amendments to section 111(d). Given the simplicity of the Senate amendment and its congruence with the numbering changes to the listing provisions of section 112, [34] EPA saw little reason to doubt that this provision was meant simply to replace the obsolete reference to section 112(b)(1)(A) with a reference to the new set of listing provisions in section 112(b). 70 Fed. Reg. 16,031. In fact, as EPA noted, the Senate amendment was labeled a "conforming amendment" in the Statutes at Large. *See* 104 Stat. 2574 (1990). For these reasons, EPA agreed that the Senate amendment "reflects the Senate's attempt to retain the pre-1990 approach of precluding regulation under CAA section 111(d)of any [hazardous air pollutant] listed under section 112(b).". 70 Fed. Reg, 16,031,

EPA explained that interpreting the text of the House amendment was, however, a somewhat more complex task. Because the House provision authorizes section 111 standards of performance for "for *any* air pollutant ... which is not ... emitted from *a* source category which is regulated under [section 112]," a literal reading of this provision could bar section 111 standards for any pollutant, hazardous or not, emitted from a source category that is regulated under section 112. *See* 70 Fed. Reg. 16,031. The Agency acknowledged, comments arguing (as the Government and Environmental Petitioners do here) that the House amendment could be read to bar section 111 standards for any hazardous air pollutant for *all* source categories once section 112 standards have been set for that pollutant in *any single* source category. *Id.* EPA responded, however, that it did not believe that such an interpretation squared with the literal text of the House provision, as it "changes the terms 'any pollutant' to '[hazardous air pollutant],' and ... changes the phrase 'a source category' to 'any source category' ...." *Id.* On the latter point, the Agency noted that the House provision referred to "a" source category, in contrast to the pre-existing term "any" air pollutant, which at least suggests that this part of the House provision could permissibly be interpreted as EPA did, *i.e.*, to refer to one rather than many source categories. *Id.*

Petitioners further argue that the textual conflict perceived by EPA between these two amendments is illusory and that *both* were intended simply to preserve the pre-1990 "status quo" and "were plainly for housekeeping purposes." Environmental Br. at 23; *see also* Government Br. at 27-29. However, as discussed in the next section, the pertinent legislative history clearly indicates that the House amendment, unlike the Senate amendment, in fact reflects a legislative intent to give EPA authority to regulate, under section 111, hazardous emissions from certain source categories not regulated under section 112. [35]

2. Pertinent legislative history supports EPA's conclusion that the House and Senate amendments to section 111(d) conflict.

The legislative history of the 1990 Amendments indicates that the shift in focus to "source categories" in the House amendment to section 111(d) was no accident, Instead, it originated as a component of a bill (H.R. 3030) that would have given EPA relatively greater discretion to determine which source categories of hazardous air emissions warranted regulation under section 112, and would have established special rules for power plants that are virtually identical to those that ultimately were enacted in the 1990 Amendments. By contrast, the Senate version of the amendment to section 111(d) had its origins in a bill that generally would have required EPA to establish source categories, and corresponding emission standards, for "all" sources of hazardous emissions, including power plants.

The text of the House's amendment to section 111(d) first appeared as section 108(d) of H.R. 3030, which was introduced on July 27, 1989. [36] As introduced, H.R. 3030 contained a proposed new section 112(c)(3) providing generally that "[t]he Administrator may decide not to list a source category or subcategory because its emissions into the air are, in his judgment, already adequately controlled under this Act or any other Federal statute or regulation." 2 1990 Legis. Hist., at 3932-33. Proposed section 112(c)(6) would have given the Administrator broad discretion to withdraw source categories that he deemed to present a "negligible risk to public health." *Id.* at 3933. The bill also contained a proposed section 112(m), which was similar to today's section 112(n)(1)(A), making any regulation of power plants contingent on a determination by EPA of whether such regulation is "appropriate and necessary" following a study of health hazards from such sources "after imposition of the requirements of this Act.". *Id.* at 3945-46.

Although the final version of H.R. 3030 differed somewhat from the version introduced in July 1989, it still contained provisions authorizing EPA to decline to add source categories, or to delete source categories already listed, based on certain health-related findings. [37] It also retained the proposed amendment to section 111(d). [38] And, most significantly, it retained (as new proposed section 112(1)) the special provision for power plants included in the original version of the bill, with wording nearly identical to the provision ultimately enacted as today's section 112(n)(1)(A), 42 U.S.C. § 7412(n)(1)(A). [39]

This history indicates that the House version of the amendment to section 111(d) was first introduced in conjunction with proposed changes to section 112 that would have given EPA broad discretion to add and withdraw source categories of hazardous air pollutant emissions from regulation under section 112, in significant part based on the extent to which such emissions already were adequately controlled under other regulatory provisions. *See* 70 Fed. Reg. 16,031. [40] This discretion was particularly explicit with respect to power plants, for which section 112 regulation was expressly deemed contingent on the outcome of a study considering the effects of these emissions after imposition of other requirements of the Act. As EPA aptly concluded, this history suggests that "the House sought to change the focus of section 111(d) by seeking to preclude regulation of those pollutants that are emitted from a particular source category that is actually regulated under section 112." *Id.* at 16,031.

For its part, the Senate amendment to section 111(d) had its roots in the version of S. 1630 reported on December 20, 1989. *See* S. 1630, 101st Cong. (1989), *reprinted in* 5 1990 Legis. Hist., at 7906. As in the final version of the 1990 Amendments, this version of the Senate bill simply proposed to change the reference to "112(b)(1)(A)" in section 111(d) to section "112(b)," and labeled this proposed change a "conforming amendment." *Compare* 5 1990 Legis. Hist., at 8153 (section 305(a)) *with* Pub. L. No. 101-549, § 302(a), 104 Stat. 2574 (1990). In contrast to H.R. 3030, the Senate bill extended far less flexibility to EPA in deciding what source categories of hazardous air pollutant emissions to add or delete from section 112. For example, while proposed section 112(c)(3) in the original version of H.R. 3030 would have allowed EPA to decide not to list a source category it believed to be already adequately regulated under other provisions, *see* 2 1990 Legis. Hist., at 3932-33, proposed section 112(c) of the Senate bill generally directed EPA to establish a list of "all" source categories and subcategories of hazardous air emissions and did not contain any express provision addressing EPA's discretion to delete source categories. *See* 5 1990 Legis. Hist. at 8077-79.

Perhaps most significantly, H.R. 3030's special provision for power plants (today's section 112(n)(1)(A)), 42 U.S.C. § 7412(n)(1)(A)), was ultimately enacted in the 1990 Amendments very nearly as initially proposed. [41] By contrast, the December 1989 version of S. 1630 (the version of the Senate bill in which the Senate's proposed change to section 111(d) first appeared) did not contain *any* similar provision. The Senate proposed a power plant subsection in a later version of S. 1630, but this proposal was markedly different from the House bill and was rejected in conference. *See* 70 Fed. Reg. 16,030-31. Although the Senate proposal would have required a study of hazardous air emissions from power plants, it still would have required EPA to promulgate emission standards for "hazardous air pollutants which are particulates and mercury emissions" from power plants in five years, simply requiring the Agency to "consider" the studies in developing the rulemaking. *See* 3 1990 Legis. Hist., at 4431-34 (proposed section 112(e)(5)). And, as EPA stressed, the Senate's provision did not call for an examination of the other requirements of the Act prior to regulation of power plants. *See* 70 Fed. Reg. 16,031.

None of this necessarily indicates that the House version of the amendment to section 111(d) should completely trump the Senate version, or vice-versa. It does, however, at the very least reinforce EPA's view that the differing text of the two amendments reflects a genuine substantive conflict rather than an inconsequential linguistic difference, as the Petitioners here suggest.

3. EPA's construction of section 111(d) represents a reasonable harmonization of the House and Senate amendments.

To reconcile the conflict between the House and Senate amendments to section 111(d), EPA construed that provision to provide that "[w]here a source category is being regulated under section 112, a section 111(d) standard of performance cannot be established to address any [hazardous air pollutant] listed under section 112(b) that may be emitted from that particular source

category." 70 Fed. Reg. 16,031. Thus, this interpretation would allow regulation of hazardous air pollutant emissions under section 111(d) from source' categories that are *not* regulated under section 112.

As the Agency explained, this construction of the statute is reasonable because it gives some effect to both the House and Senate provisions. It gives effect to the Senate provision by making clear that where it applies, the section 111(d) exclusion only extends to regulation of hazardous air pollutants, not hazardous *and* non-hazardous air pollutants, as a literal reading of the House amendment appears to require. 70 Fed. Reg. 16,032. By the same token, "it gives effect to the House's desire to increase the scope of EPA's authority under section 111(d) and to avoid duplicative regulation of [hazardous air pollutants] for a particular source category" *Id.* [42]

For their part, Petitioners argue that the phrase "a source category" in the House amendment should be read to mean "any source category;" if construed in this way, they argue, there would be no practical conflict between the House and Senate versions of section 111(d), because section 111 regulation would be barred for any hazardous air pollutant whose emissions from *any* source category are regulated under section 112. Environmental Br. at 22; Government Br. at 27-28. Without citing any support for this proposition, the Environmental Petitioners simply assert that the "plain meaning of "a" is "any" and that this allegedly plain meaning should be given effect. Environmental Br. at 22. EPA reasonably rejected this statutory argument.

As EPA recognized, *see* 70 Fed. Reg. 16,031, from a purely semantic perspective, without considering legislative history or context, the usage of the word "a" in the House amendment to section 111(d) is ambiguous. The dictionary explains that the indefinite article "a" is used "as a function word before most *singular* nouns ... when the *individual* in question is undetermined, unidentified, or unspecified...." *Webster's Third New International Dictionary*, at 1 (1967) (emphasis added)(giving, as an example, the phrase "there was a tree in the field"). [43] This suggests that the term was intended as a reference to a particular but unspecified source category, just as EPA construed it. *See* 70 Fed. Reg. 16,031. On the other hand, the dictionary recognizes that "a" can have an alternative meaning of "any" when it is followed by a restrictive modifier (such as in the phrase "a man guilty of kidnaping wins scant sympathy"). *Webster's* at 1. This alternative meaning arguably could apply here, because the term "a source category" in the House amendment is immediately followed by the phrase "which is regulated under section 112 of this title."

Given the existence of this ambiguity, the Court should defer to EPA's reasonable construction of the provision, which is strongly supported by other ??

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?? 1990 focus on listed pollutants. *See e.g.,Donnelly v. FAA*, 411 F.3d 267, 271 (D.C. Cir. 2005) (statutes should not be construed to render certain provisions "mere surplusage"). Under CAA section 112(c)(1), 42 U.S.C. § 7412(c)(1), EPA is generally directed, among other things, to list "all" major source categories of emissions of hazardous air pollutants listed pursuant to section 112(b), 42 U.S.C. § 7412(b), Therefore, to construe the House's amendment to section 111(d) to authorize section 111 standards only for those hazardous air pollutants that are not emitted from *any* source category listed under section 112 comes close to rewriting the House amendment to simply prohibit section 111 standards for emissions of any pollutant listed under section 112(b). Presumably, however, if the House had intended to proceed in this fashion, it could have adopted a type of simple conforming amendment like the Senate did, rather than inserting a wholly new phrase focusing on source categories into section 111(d).

Nor is it accurate to suggest, as Petitioners do, that interpreting the House amendment in the manner they favor is acceptable because it is consistent with what Petitioners perceive to be Congress' *overall* intent to continue the pre-1990 bar on section 111(d) regulation of any hazardous pollutants listed under section 112. As detailed above, it is indisputable that the House version of the amendment to section 111(d) was born as part of a proposed "regulatory scheme ??

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?? Authority") argues, on several grounds, that EPA did not allocate an appropriate number of annual mercury allowances in establishing the budget for the State of Alaska. The Bituminous Petitioners argue that EPA's adjustment factors for coal ranks are inappropriate. Finally, Petitioner ARIPPA argues that EPA used an incorrect heat content number for coal refuse when calculating emissions limits under CAMR. As will be explained below, however, none of these challenges has merit.

A. A Cap-and-Trade System Is An Appropriate "Standard of Performance" For Existing Sources Under the Act.

In contrast to section 111 standards for new sources, where EPA promulgates standards of performance directly, CAA section 111(d), 42 U.S.C. § 7411(d), directs EPA to establish a procedure similar to the SIP process under CAA section 110, 42 U.S.C. § 7410, by which States adopt standards of performance for existing sources pursuant to EPA criteria and oversight. Pursuant to these provisions, EPA promulgates national "emission guidelines" for certain air pollutants from existing sources, *see* 40 C.F.R. § 60.23, and States then submit plans that "establish[] standards of performance" and "provide[] for the implementation and enforcement of such standards of performance." 42 U.S.C. § 7411(d). EPA retains specified oversight and enforcement authority to assure these state plans are properly developed and implemented. *Id.* § 7411(d)(2). Pursuant to EPA's regulations, standards of performance adopted by States are, *inter alia*, to be no less stringent than the national "emission guidelines" established by EPA. *See* 40 C.F.R. § 60.24(g); *see also id.* § 60.24(c). In addition, CAA section 116, 42 U.S.C. § 7416, authorizes States to adopt section 111 standards that are more stringent than the corresponding minimum federal emission guideline. In this case, EPA promulgated 40 C.F.R. § 60.24(h), which creates the pertinent emission guidelines for power plants, and subpart HHHH of 40 C.F.R. Part 60, which establishes a model trading rule States can adopt as a means of implementing these guidelines. *See* 70 Fed. Reg. at 28,657.

The term "standard of performance" is defined in section 111 as "a standard for emissions of air pollutants which reflects 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." 42 U.S.C. § 7411(a). In this case, EPA reasonably construed this provision of the Act to permit state participation in a cap-and-trade system, pursuant to corresponding, federal emission guidelines, as a standard of performance under section 111. *See generally* EPA-HQ-OAR-2002 0056-6214, Response to Significant Public Comments on CAMR ("CAMR RTC") at 9-268 to 9-273 (JA 2105-10).

EPA explained that a cap-and-trade program like that adopted in CAMR "reduces the overall amount of emissions by requiring sources to hold allowances to cover their emissions on a one-for-one basis; by limiting overall allowances so that they cannot exceed specified levels (the 'cap'); and by reducing the cap to less than the amount Of emissions actually emitted, or allowed to be emitted, at the start of the program." 70 Fed. Reg. 28,616/3. By authorizing trading of allowances, the program "maximizes the cost-effectiveness of the emissions reductions in accordance with market forces." *Id.* This is because sources that can cost-effectively reduce emissions below their allowed level will have an incentive to do so since they can sell excess allowances (or avoid having to buy additional allowances). Conversely, sources that cannot do so will likely want to purchase allowances, thereby supporting the creation of an efficient market. *Id.*

EPA reasonably viewed this approach as entirely consistent with the statute because it satisfies the three substantive components of the section 111(a)(1) definition of "standard of performance": (1) a "standard for emissions of air pollutants;" (2) "which reflects the degree of emission limitation achievable;" (3) "through the application of the best system of emission reduction." 70 Fed. Reg. ??

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For these reasons, it was at the very least "permissible" for EPA to construe the statutory definition of "standard of performance" in section 111 to allow the type of cap-and-trade system reflected in CAMR. Nonetheless, Environmental Petitioners raise a multi-faceted legal challenge to this conclusion, arguing that EPA was required to establish source-specific, and generally more

stringent, emission limits. As legal support for this conclusion Petitioners rely on: (1) the reference to "any existing source" in section 111(d), 42 U.S.C. § 7411(d); (2) a different CAA definition of "standard of performance" in CAA section 302(1), 42 U.S.C. § 7602(1); and (3) this Court's decision in *Asarco, Inc. v. EPA*, 578 F.2d 319 (D.C. Cir. 1978). *See* Environmental Br. at 25-28. These arguments are mistaken.

Petitioners are correct that section 111(d)(1), 42 U.S.C. § 7411 (d)(1); directs that standards of performance for existing sources be applied to "any existing source." Environmental Br. at 27. However, this is precisely what CAMR does, because any existing source is subject to the existing source standard and meets this obligation by holding sufficient emission credits to coverall its mercury emissions. *See* 70 Fed. Reg. 28,617. Nothing in the statutory directive that existing source standards of performance apply to "any existing source" mandates that this requirement be technological, as Petitioners suggest.

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???? suggests that Congress' decision not to include the terms "technological" and "continuous" in the post-1990 section 111 (a) definition of standard of performance was at least to some extent deliberate.

Moreover, Petitioners' argument overlooks that, as discussed above, CAA section 111(d), 42 U.S.C. § 7411(d), directs that existing source standards of performance be established through "a procedure similar to that provided by section 7410 of this title [CAA section 110] under which each State shall submit to the Administrator a plan...." This procedural cross-reference to section 110 certainly does not supersede the substantive criteria set forth in section 111(a)(1) and the remainder of section 111(d). However, where, as here, a proposed cap-and-trade system *meets* those criteria (*e.g.*, that it is a "standard" applicable to "any existing source" because it requires each source to cover its emissions with allowances), it is an additional sign of the reasonableness of CAMR that it is structured in a manner similar to that used successfully in rules adopted pursuant to section 110 (as well as other CAA authorities). *See* 70 Fed. Reg. 28,617; CAMR RTC at 9-271 to 9-272 (JA 2108-09). [48]

Petitioners' reliance on the definition of "standard of performance" in section 302(1)of the Act's general definitions, 42 U.S.C. § 7602(1), is also misplaced. While section 302's definitions do apply to the "chapter" (*i.e.*, the Act) as a whole, 42 U.S.C. § § 7602, they are still subject to the well-settled canon of statutory construction that "[h]owever inclusive may be the general language of a statute, it will not be held to apply to a matter specifically dealt with in another part of the same enactment." *Fourco Glass Co. v. Transmirra Prods. Corp.*, 353 U.S. 222, 228 (1957)(citations and quotation marks omitted). Therefore, "[s]pecific terms prevail over the general in the same or another statute which otherwise might be controlling." *Id.* at 228-29 (citation and quotation marks omitted). In this case, while the definitions in section 302 ordinarily apply to the "chapter" as a whole, the definitions in section 111(a) apply only to "this section," and therefore the section 111(a) definitions are more specific and control here. *See* CAMR RTC at 9-270 (JA 2107).

In any event, as EPA explained, even if the section 302 definition of "standard of performance" had some relevance here, it too is reasonably construed to allow the adoption of a cap-and-trade system. *See* 70 Fed. Reg. 28,617. That provision defines a "standard of performance" to mean a "requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." 42 U.S.C. §7602(1). Environmental Petitioners challenge EPA's interpretation of this provision by contending that it requires "each source subject to this standard to demonstrate 'continuous emission reduction,' " and that this requirement is not met by a cap-and-trade system that may allow some sources to purchase extra allowances instead of reducing actual emissions. Environmental Br. at 26. However, EPA reasonably viewed CAMR's cap-and-trade system as satisfying section 302(1), since the overall cap is set below current emission levels (and hence is a "requirement of ... emission reduction") and is "continuous" insofar as "there is never a time when sources may emit without needing allowances to cover those emissions." 70 Fed. Reg. 28,617; CAMR RTC at 9-270 to 9-271 (JA 2107-08). This understanding of "continuous" is consistent with the usage of that term elsewhere in the Act. For example, CAA section 302(k), 42 U.S.C. § 7602(k), defines the term "emission limitation" to include the concept of "continuous" reductions, and in CAA Title IV-A (Acid Deposition Control), Congress used the term "emission limitation" to include a cap-and-trade program. *See* 42 U.S.C. §§ 7651b(a)(1), 7651C(a)(1).

In addition, as we will discuss in more detail below, *see infra*, Section VI.B.1., the fact that a cap-and-trade system might allow some particular sources to increase emissions is an inherent aspect of *any* standard of performance for existing sources, since such standards will always have to be set at some degree below the level of performance achieved by the best-performing sources. Stated another way, under any national standard of performance, sources that were already among the better performers will often be able to meet the standard even if their emissions increase to some extent. A cap-and-trade system actually represents an *improvement* on this type of situation, since better-performing sources will have an economic incentive to keep their emissions low and sell their excess allowances, rather than increasing their emissions.

Finally, the Environmental Petitioners also err in premising much of their argument on these issues on *Asarco, Inc. v. EPA*, 578 F.2d 319 (D.C. Cir. 1978). *See* Environmental Br. at 28-29. In fact, *Asarco* is irrelevant to the issues presented here. *Asarco* did not construe the definition of "standard of performance" nor did it address the regulation of *existing* sources under CAA sections 111(a)(1)&(d), which are the statutory bases for the cap-and-trade system in CAMR. Rather, *Asarco* concerned only new (or modified) sources and the definition of "source." Specifically, in *Asarco*, this Court held only that the statute precluded EPA from allowing a facility to avoid application of the *new source* standard of performance as a result of a "modification" by employing the so-called "bubble concept," *i.e.*, an approach that "treat[s] a combination of facilities as a single source" thereby "allow [ing] a facility whose emissions are increased by alterations to avoid complying with the applicable NSPS as long as emission decreases from other facilities within the same 'source' cancel out the increase from the altered facility." *Asarco*, 578 F.2d at 326. *Asarco* did not address whether the term "standard of performance" could include a cap-and-trade program that applies to each source and that allows emissions trading *among* sources (as opposed to netting of emissions among individual units within a source to avoid application of a standard of performance). [49] Thus, even if *Asarco* is taken on its own terms, [50] CAMR is fully consistent with that case since, as discussed above, it sets a standard of performance that applies to each source through the requirement that each source cover its emissions with allowances. [51]

For all the foregoing reasons, EPA reasonably construed the statute as authorizing the adoption of a cap-and-trade system as a "standard of performance" for existing sources under CAA section 111(d).

B. Environmental and Government Petitioners' Record-Based Challenges to CAMR are Meritless.

Environmental and Government Petitioners also posit a handful of primarily record-based challenges to CAMR, apparently in an attempt to demonstrate that the rule does not represent the "best system of emission reduction" or that it did not adequately account for "nonair quality health and environmental impact [s]" within the meaning of CAA section 111(a)(1), 42 U.S.C. §7411(a)(1). *See* Government Br. at 29-35; Environmental Br. at 26-28. On each of these points, however, the Petitioners' challenge fails because the Agency clearly considered the relevant factors and made reasonable judgments based on the record. *See, e.g.*,*Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402, 416 (1971). This is particularly tree given the considerable discretion that EPA has in applying the various factors reflected in section 111. *SeeLignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them"); *see also, e.g.*,*New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992) (similar).

1. The fact that some localized emission increases may be allowed under CAMR does not make it an arbitrary national performance standard, since the rule as a whole will achieve dramatic and cost-effective reductions in mercury emissions throughout the country.

CAMR is the first national rule ever adopted by EPA specifically intended to reduce mercury emissions from power plants. Under CAMR's cap-and-trade system, nationwide mercury emissions are capped at 38 tons in 2010, then the cap is further reduced to 15 tons in 2018. 70 Fed. Reg, 28,619. EPA's modeling projects that, as compared to a 1999 baseline, this system will result in a 35 percent mercury emission reduction in 2010, a 42 percent reduction in 2015, and a 50 percent reduction in 2020. *Id.*

EPA explained that because the first phase cap is set at the level of expected co-benefits from the CAIR rule (which is targeted at control of emissions of NO_x and SO_2, but which also incidentally controls mercury emissions), it will be both cost-effective and technologically feasible, since it will make use of the same demonstrated technologies that power plants already will be installing to meet their CAIR obligations. *Id.* at 28,617-21, 28,640. The second phase cap, which is set substantially lower, is expected to require power plants to make use of a combination of CAIR co-benefits *and* mercury-specific controls, *id.* at 28,620-21, but is timed so that "new technologies can be developed, installed, demonstrated and commercially deployed with little impact to the stability of the power grid." *Id.* at 26,621; *see also id.* at 28,619.

Given these facts, EPA undoubtedly had a solid basis in the record for concluding that CAMR's cap-and-trade system satisfied the pertinent criteria set forth in section 111, *i.e.*, that it reflects the "best system of emission reduction" that "the Administrator determines has been adequately demonstrated," taking into account "the cost of achieving such reduction and any nonair quality heath and environmental impact and energy requirements." 42 U.S.C. § 7411 (a)(1). As the Agency explained, the hard caps, which are based on calculated mercury emissions from each power plant in the country, assure that the rule will achieve real and meaningful nationwide emission reductions, while the trading system helps make sure that these results are achieved in as cost-effective a manner as is possible. *See* 70 Fed. Reg. 28,616; *see also* Reconsideration RTC at 302 (JA 3902).

The Environmental and Government Petitioners do not appear to assert any direct challenge to the adequacy of either of the two hard caps reflected in CAMR, nor do they posit any specific challenge to the methodology EPA employed in deciding the state-by-state allocations to meet those caps. They nonetheless argue that CAMR is inadequate because, in their view, some sources could make greater emission reductions than CAMR requires, Government Br. at 30, the role will allow mercury emissions by some sources and in some States in total to increase, *see* Government Br. at 31-32; Environmental Br. at 26-27, and that the rule allegedly will not do enough to address so-called "hotspots" of local mercury emissions. Government Br. at 32-35. None of these claims has merit.

First, and most generally, the fact that certain *individual* "best performing power plants," Government Br. at 30, might be able to achieve greater emission reductions than is required by CAMR is (as will be discussed in more detail below) irrelevant to CAMR's reasonableness as a *national* standard of performance for *all* power plants. *See* Reconsideration RTC at 284 (JA 3897).[52] CAMR's new source performance standards and Phase I and Phase II caps were based on a rigorous analysis of currently available controls and the extent to which power plants could feasibly implement these controls. *See* 70 Fed. Reg. 28,614-15 (summarizing record data and analyses on these issues). This record shows that EPA's consideration of these issues was thorough and reasonable, and Government Petitioners have failed to identify any specific flaw in this analysis.

On a more general level, Government Petitioners do vaguely suggest that the Phase I cap is somehow overly lax because EPA did not explain why it set that cap at 38 tons rather than 31 tons. Government Br. at 30. To begin with, it does not appear Petitioners raised this specific concern to EPA in comments, so they may not raise it here. In any event, EPA clearly explained that it set the Phase I cap at the level of modeled co-benefits (38 tons) expected under the CAIR role by 2010. 70 Fed. Reg. 25,218-19; *see also infra* Section VI.D (response to Development Authority's challenge). EPA also noted that its modeling indicated that early adoption of the more stringent (and mercury-specific) controls by some sources to meet CAMR's Phase II cap might result in actual mercury emission levels as low as 31 tons in 2010. 70 Fed. Reg. 25,218-19. However, the Agency also reasonably explained why it believed *nationwide* adoption of mercury-specific controls would not be adequately demonstrated prior to the Phase II cap. *See generally* 70 Fed. Reg. 28,614-15. In addition, the Agency explained that "the existence of a hard cap in 2010 will create the incentive for additional reductions beyond [CAIR] cobenefits, so thai sources can bank allowances for furore use." Reconsideration RTC at 207 (JA 3856); *see* also RIA at 7-3 (JA 2025).

EPA also fully considered and responded to the allegation that the mercury budgets for some individual States may be higher than their current level of mercury emissions, even though significant reductions in nationwide emissions are reflected in CAMR's overall emissions cap. *See* Reconsideration RTC at 300-02 (JA 3900-02). While EPA did not dispute that such instances indeed exist, it explained that this is simply the result of the methodology used to allocate in a fair and supportable manner each State's

share of the overall cap - a, methodology that is not challenged by the Government and Environmental Petitioners in this case. *Id.* at 302. [53] In addition, the great majority of these instances occur prior to the second phase of CAMR, and are related to EPA's determination that nationwide adoption of mercury-specific technology will not be adequately demonstrated prior to the second phase of CAMR. *See* 70 Fed. Reg 28,618, 28,620-21.

Far from indicating that CAMR is arbitrary, such variations are an inherent and completely proper facet of *any* national standard of performance, whether based on a cap-and-trade system or not. *Id.* A standard of performance - particularly for *existing* sources, as is the case here - will always be set at some level lower than the capability of the best-performing sources, since the standard must be achievable and must take into account costs and the remaining useful life of the subject facilities. *Id.; see also* 42 U.S.C, §§ 7411(a)(1); 7411(d)(2). As this Court observed in considering such issues over 25 years ago, "[t]he language of section 111 ... gives EPA authority when determining the best technological system to weigh cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present." *Sierra Club. v. Costle*, 657 F.2d 298,330 (D.C. Cir. 1981). [54] As standards of performance for existing sources are not set at the level of performance achieved by the single best performing source, there will always be sources, and, therefore, potentially States, where emissions from existing sources can increase consistent with the existing source, standard of performance.

In this case, because individual state mercury emission budgets are, in effect, based on a combination of the assessment of *average* projected emission limitations achievable by power plants on a nationwide basis, and the ratio of the heat input of individual sources in particular subcategories Within the State to the national total, *see* 70 Fed. Reg. 28,621-22, to the extent that some particular sources are, in practice, limiting mercury emissions to a greater extent than on average, that State may well have a higher mercury budget than the amount of mercury currently being emitted by its contingent of generally above-average performers. *See* Reconsideration RTC at 302 (JA 3902). None of this means, however, that once the State allocates allowances to these better-performing sources these sources will increase their actual emissions up to the amount of their allocation. [55] To the contrary, the trading system provides these sources with an economic incentive to keep their emissions low so that they can sell their excess allowances. *Id.* And most importantly, "by placing a hard cap on [mercury] emissions and accounting for each individual ounce of [mercury] emitted, [CAMR] guarantees that significant reductions in nationwide [mercury] emissions will be achieved." **Id.**

Petitioners' challenge to CAMR based on its alleged failure to address local "hotspots" of mercury pollution is meritless for similar reasons. To begin with, as discussed elsewhere in this brief, Petitioners' assertions regarding the existence of hotspots attributable to mercury emissions from power plants following implementation of CAMR are refuted by EPA's utility hotspot analysis. [56] Furthermore, as EPA explained, the Agency intends to keep reviewing CAMR's standards of performance. Reconsideration RTC at 290-91 (JA 3898-99). Should additional information be developed in the future concerning the existence of such hotspots, EPA would consider this information in the course of its review of these standards. *Id.*; 70 Fed. Reg. 16,027-28.

For all of these reasons, Petitioners' claims regarding potential local and regional emission increases or hotspots simply do not render CAMR an improper national standard under section 111.

2. CAMR's subcategorization is appropriate.

Nor is CAMR undercut by Government Petitioners' vaguely-articulated claims regarding subcategorization. *See* Government Br. at 31. By way of background, under CAA section 111 (b)(2), 42 U.S.C, § 7411(b)(2), EPA is authorized to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [section 111 new source] standards.". In CAMR, EPA subcategorized sources primarily by the type of coal they use ("coal rank"). 70 Fed. Reg. 28,612. [57] In general, this subcategorization results in somewhat different emission limitations for new sources in different subcategories,

and it also affects the calculation of state mercury budgets, for existing sources, which depends to some extent on the mix of different types of facilities in each State.

As EPA explained, it historically has taken a similar approach in setting section 111 standards of performance for SO_2 and NO_x emissions from power plants, with such subcategorization reflecting "the differences in the relative ability of the respective control technologies to effect emissions reductions on the various coal ranks." *Id.* at 28,612. This type of approach was thoroughly considered and upheld by this Court in the 1981 *Sierra Club* decision. EPA further explained that while advances in emission control, technology have led the Agency to more recently reevaluate, certain aspects of this approach for emissions of SO_2 and NO_x, coal rank still materially affects the ability of control technology to reduce *mercury* emissions, so the Agency therefore viewed it as reasonable to subcategorize standards of performance for mercury emissions in this-manner. 70 Fed. Reg. 28,612-13; *see also infra,* Section VI.E (discussing these issues as they apply to the arguments raised by the Bituminous Petitioners).

Government Petitioners do not present any direct challenge to the subcategories reflected in CAMR, but they do vaguely charge that subcategorization "further diluted" the standards set in CAMR, which Petitioners characterize as already "weak" for other reasons. Government Br. at 31. To the extent this claim is understood as a challenge to the appropriateness of *ever* subcategorizing by coal rank in setting standards of performance for power plants, it would appear to be foreclosed by this Court's 1981 decision in *Sierra Club*, *supra*, a case which Petitioners do not even mention. To the extent this claim is intended as a factual challenge to particular aspects of the CAMR subcategorization scheme, it is refuted by the record.

One factual claim made by Petitioners is that CAMR's subcategorization scheme "fails to reflect that 'a number of Utility Units co-fire different ranks of coals.' " Government Br. at 31 (citation omitted). However, EPA fully considered this issue and explained that "[b]oilers designed to burn one fuel (e.g., lignite) cannot randomly or arbitrarily change fuels without extensive testing and tuning of both the boiler and the control device." 70 Fed. Reg. 28,613. Because of engineering and design constraints, even where utilities do burn different ranks of coal, "the practice is only done with ranks that have similar characteristics to those for which the boiler was originally designed." *Id.* Therefore, any fuel switching among different ranks of coal is relatively limited and does not "negate the overall differences in the ranks that preclude universal coal rank switching." *Id.* For these reasons, EPA reasonably concluded that, notwithstanding the fact that some power plants co-fire different ranks of coal, fuel rank "is most suitable for use as a basis for subcategorization." *Id.* Petitioners do not mention, let alone rebut, EPA's discussion of this issue.

Government Petitioners also charge that EPA impermissibly subcategorized power plants based on the type of emission control technology they use. Government Br. at 31. Contrary to Government Petitioners' assertion, EPA made clear on reconsideration that it had subcategorized on the basis of water availability, not control technology.[58] As a result of this legitimate and essentially unchallenged[59] "nonair quality environmental" basis for subcategorizing, EPA ended up setting one emission standard for those units in relatively wet areas based upon the use of wet flue gas desulfurization Systems, and another (somewhat less stringent) standard for those units in the West and other dry areas, based on the use of dry flue gas desulfurization systems. EPA's rationale on this point was clearly explained and entirely appropriate. *Cf. Sierra Club,* 657 F.2d at 330 (approving a variable performance standard for new sources based in part on the relative capabilities of wet and dry systems and recognizing that wet systems might be " 'best' in the East where water is plentiful, but environmentally disastrous in the water-scarce West").[60]

C. CAMR Appropriately Gives States Flexibility to Allocate Emission Allowances And/Or To Opt Out of EPA's Recommended Emission Trading Program.

As noted above, while CAMR requires that each State adopt plans to meet the mercury emission reductions reflected in its budget, the role generally leaves States discretion to determine how best to allocate emission allowances to particular sources in the State, to allocate fewer than all the allowances, and even to opt out of the trading system. *See* 70 Fed. Reg. 28,624,

28,627-29; *see also* CAMR RTC at 5-200 to 5-201 (SJA 76-77). Petitioner UARG argues that giving States this degree of flexibility is improper, as it believes such an approach undermines EPA's judgment as to the features of the "best" system of emission reduction within the meaning of section 111(a)(1), 42 U.S.C. § 7411(a)(1). *See* UARG Br. at 7-9.

UARG's challenge is meritless. There is no basis for the contention that a State's choice to allocate allowances in a manner different than would result from EPA's suggested methodology somehow undermines EPA's rationale in adopting the role. Quite to the contrary, EPA expressly stated that "EPA maintains that the choice of allocation methodology does not affect the achievement of the specific environmental goals of the CAMR program." 70 Fed. Reg. 28,627, 28,629. EPA further explained that it believes economic forces will generally serve to create "environmentally similar outcomes regardless of the manner in which allowances are initially distribute." *Id.* at 28,627.

The same Conclusions hold true with regard to the possibility that some States may opt out of CAMR's trading program. EPA has clearly shown that the States that would remain in the CAMR trading program would not be disadvantaged were other States to opt out. Specifically, EPA determined that CAMR met the requirements for a standard of performance for existing sources based on per ton marginal costs, as determined by use of the Integrated Planning Model ("IPM"). *See* EPA-HQ-OAR-2002-0056-6304, *Cost and Energy Impacts - Technical Support Document* ("Cost TSD") at 7 (noting marginal costs of $23,200 in 2010, $30,100 in 2015, and $39,000 in 2020) (JA 2420). Some States submitted comments stating that they would opt out of the cap-and-trade program, and EPA recognized that "[t]he cost effectiveness of a cap-and-trade program under CAMR could be reduced if States that are projected to be net sellers of allowances opted not to participate in the cap-and-trade program, as this would effectively increase the stringency of the cap for States that did choose to participate ..." *Id.* at 28 (JA 2441).

To determine the extent of any change in marginal costs, EPA re-ran its model assuming non-participation in the cap-and-trade program by the net-seller States who had indicated in the record that they may take such a course (California, Connecticut, Illinois, Minnesota, New Hampshire, and Pennsylvania), and the resulting data indicated that "the potential decision of the States named above not to participate in the CAMR trading program would not significantly affect marginal costs within the program."*Id.* at 29 (JA 2442); *see also id.*, Table 34 (showing modeling results) (JA 2442). Specifically, such marginal costs would only increase by about one-tenth of one percent in 2010, and by one-fifth of one percent in 2020. In its brief, UARG nowhere mentions, much less refutes, this analysis, nor does UARG posit any reason to believe that the assumptions underlying EPA's opt-out analysis were flawed or unreasonable. For this reason, there is no basis on this record for UARG's suggestion that the possibility that some States may opt out of the trading program will make CAMR unreasonably costly for sources in those States that will participate in the trading program.

Nor is UARG correct in asserting that CAMR is undermined for the States that impose more stringent controls on sources within their own borders than would be strictly necessary to meet the minimum requirements of the CAMR trading program (either by allocating fewer allowances or by choosing not to participate in the trading program). Although a "standard of performance" under section 111(a)(1), 42 U.S.C. 7411(a)(1) must be based on the "best system," that provision clearly allows States to establish standards of performance more stringent than EPA's guidelines. Indeed, this was expressly noted in Committee reports for the 1977 Amendments.[61] In addition, CAA section 116, 42 U.S.C. § 7416, allows States to adopt standards that are more stringent than the minimum federal requirement specified pursuant to section 111, 42 U.S.C. § 7411. Similarly, EPA's regulations have provided for decades that States can adopt more stringent standards of performance than the standards EPA promulgates under section 111(d). *See* 40 C.F.R. §§ 60.24(c), 60.24(g). Together, these authorities mean that state rules that are more stringent than the EPA-promulgated guidelines are, by definition, part of the "best" system of emission reduction within the ??

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Finally, there also is no merit to UARG's wholly unsupported conclusion that where a State chooses to submit a plan that reflects more stringent emission reductions than the minimum required by CAMR, such additional limitations may not be federally enforceable. UARG Br. at 9. This conclusion appears to be based on the premise that the plan cannot qualify as a standard

of performance under CAMR, a premise that is incorrect for all the reasons discussed above. Thus, any standards adopted by a State under a section 111 plan approved by EPA are fully enforceable by the State and by EPA pursuant to the statutory authorities outlined in the Act. *See* 42 U.S.C. §§ 7411(c), 7411(d)(2)(B); 40 C.F.R. § 60.24(g).

For all the foregoing reasons, UARG's challenges to CAMR should be denied.

D. EPA Reasonably Allocated Mercury Emissions for Alaska Within the Section 111(d) Trading Program.

Petitioner Development Authority argues that, under CAMR, the State of Alaska was not given a sufficient per-year mercury emissions allocation. This argument is based on the Development Authority's contentions that (1) EPA cannot establish state caps based on an estimate of present emissions of all existing Units in the State, after application of controls, but instead must consider and allow for expectations for future emissions growth from these same units; and (2) that EPA has failed to adequately demonstrate that the performance standard for existing sources can be achieved and has failed to properly balance the costs and benefits of that standard.

As discussed in detail above, CAMR sets out state-specific emissions budgets based upon a summing of hypothetical unit allocations, which EPA derived from heat input and coal rank. *Supra* § VI(A). Development Authority does not challenge the general framework but instead argues that EPA should have granted Alaska a bigger budget because one of the two units in the State expects to increase its capacity, and hence its emissions, in the furore. Development Authority's arguments disregard the overall purpose and structure of CAMR and misconstrue the emissions trading program authorized by the rule.

1. EPA, through the mercury emissions allocation process, appropriately calculated state emissions budgets.

EPA reasonably construed CAA section 111(d) in deciding to use available data on heat input and then imposing a state emissions budget that reflected that heat input coupled with the achievable emissions limitations on which the rule was based. 70 Fed. Reg. 28,622. Contrary to Development Authority's contentions, nothing in section 111(d) requires EPA to set state budgets that make allowances for expected growth In emissions at a power plant.[63] Moreover, Development Authority's arguments fails to acknowledge the primary goal of CAMR to reduce the overall quantity of mercury emissions nationwide.

First, Development Authority's reliance on CAA section 111(d)(2), which requires EPA to consider, in promulgating a standard of performance under a plan issued pursuant to its authority under that section, “among other factors, remaining useful lives of the sources in the category, of sources to which such standards apply,” is misplaced. 42 U.S.C. § 7411(d)(2). Based on the plain language used, the consideration is only relevant in the context of promulgating an implementation plan, and not in establishing the emission guidelines represented by CAMR. Further, EPA reasonably interprets this provision as requiring EPA to consider whether a unit is going to remain in operation long enough to justify the cost of compliance, not as requiring EPA to provide a relatively new power plant with a less stringent level of control relevant to its current emissions simply because it may increase its emissions in the future. *See, e.g.*, 40 C.F.R. § 60.27(e)(2).

Development Authority further argues that it is disadvantaged because the Healy Clean Coal Project facility (“HCCP”), one of only two facilities in the State of Alaska that is eligible to be regulated under CAMR, is caught between being a “new” and “existing source.” Development Authority Br. at 6. If HCCP had been considered a “new” source, however, its heat input would not have been included in calculating Alaska's budget; HCCP would have been allocated no allowances under the model rule and would have been required to meet the new source emission limit. *See* 42 U.S.C. § 111(f). By considering HCCP's emission data and, thus, treating it as an existing source, EPA's approach allowed Alaska a higher emissions cap.

Development Authority further claims that EPA should have considered. HCCP's potential capacity because the term “modification” in an entirely different regulatory context has been interpreted by the Seventh Circuit to be a contingent on the capacity of a stationary source. Development Authority Br. at 7. This argument takes the defined term “modification” out

of context. Development Authority refers to a definition of "modification" set out in section 111(a)(4). This definition sets out when a physical change in a stationary source subjects the stationary source to regulation as anew source. 42 U.S.C. § 7411(a)(4) (defining "modification" as ' 'any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted''). While the definition of "modification" is relevant when determining whether a source should be considered a ' 'new" source or an "existing" source, it is irrelevant to determining "the best system of emissions reduction," and Development Authority fails to cite any relevant case or statutory authority in support of its position.

Development Authority also argues that Alaska cannot reduce mercury emissions to its budgeted level for three reasons: (1) Alaska is not a CAIR State; (2) state-of-the-art controls are already installed at the HCCP; and, (3) further control devices are technologically infeasible. Development Authority Br. at 8-12. These arguments misconstrue the function of EPA's Phase 1 cap. EPA set its national Phase 1 cap at a level that could be achieved as a "co-benefit" of control technology that would be necessitated by CAIR. 70 Fed. Reg. 28,617. It is not necessary, however, for every power plant to be subject to CAIR for the system to work effectively. Each participating State makes individual unit allocations and power plants are able to purchase emission allowances on the market if they wish to do so. EPA never assumed that every power plant would install controls to comply with CAIR. Nor did EPA assume that every plant that did install controls would be able to operate consistent with their yearly unit allocation based on CAIR co-benefits alone. The fact that HCCP anticipates that it will have to purchase allowances is, therefore, consistent with EPA's chosen approach and, contrary to Development Authority's assertion, does not undermine EPA's system of calculating state emission budgets.

Development Authority seems to claim a right to emissions allowances that would allow for increased emissions without requiring the application of new control technology or the purchase of emissions allowances in the marketplace. Nationwide application of such a methodology would defeat the purpose of CAMR by establishing nationwide emissions limits that are higher than mercury emission levels estimated in 1999 - *i.e.*, there would be no overall reduction in mercury emissions from existing sources.

Instead of adopting Development Authority's preferred approach, EPA consistently applied an approach of establishing a baseline heat input estimate based on the actual historical heat input data (or, in some cases, actual historical fuel use and heat content data) for coal-fired units. EPA apportioned the national cap on a consistent basis among the 50 States, two Tribes, and the District of Columbia. To use a different approach solely for the State of Alaska would be unreasonable. State Budgets TSD (JA 1769-80). Furthermore, each State has authority to allocate emissions allowances as it deems appropriate as long as the total allocated does not exceed the State's total budget. If the State of Alaska chooses to do so, it could allocate its entire emissions budget to HCCP, part of its budget to HCCP, or even none of its budget to HCCP. 70 Fed. Reg. 28,627.

In short, EPA reasonably calculated an emissions budget for the State of Alaska.

2. Development Authority unreasonably assumes that the CAMR cap-and-trade system will fail.

There is nothing unique about Alaska with regard to the cap-and-trade system. Development Authority expressed fear that interstate trading of mercury allowances was unlikely because States might choose not to participate in the cap-and-trade program. Development Authority Br. at 10-12; Reconsideration RTC at 240-41 (JA 3878-79). EPA, however, reasonably concluded that there will be a viable allowance market based on IPM analysis. *See supra* § VI(C); Reconsideration RTC at 243 (JA 3881); 70 Fed. Reg. 28,619. Using sophisticated IPM modeling, EPA analyzed the impact on projected marginal costs of certain States, even a significant number of States, not participating in the CAMR trading program and concluded that the potential decision of certain States not to participate in the trading program would not significantly affect marginal mercury control costs within the program. *Supra* § VI(C); Cost TSD at 28, (JA 2441); EPA-HQ-OAR-2002-0056-6449, (JA 2540). [64] This factual support underlying the CAMR mercury trading program is in stark contrast to *National Lime*, cited by Development Authority, in which this Court found that the administrative record failed to support the "achievability" of the standards set for

lime manufacturing plants. *National Lime Ass'n v. EPA*, 627 F.2d 416; 431 (D.C. Cir. 1980). EPA's IPM analysis demonstrates that the standard is achievable by all affected power plants through the use of one or more available compliance approaches.

Furthermore, a cap-and-trade program assures that reductions will be achieved with the least cost. 70 Fed. Reg. 28,619. The benefits of the cap-and-trade system are numerous: among other things, it grants a high degree of flexibility for the regulated community without resorting to waivers, exemptions and other forms of administrative relief. EPA, therefore, reasonably concluded that these benefits will motivate States to adopt the cap-and-trade system even though they are not required to do so. *Id.* at 28, 619, 28, 627; 69 Fed. Reg. 4701-03 Accordingly, EPA adequately demonstrated the viability of the mercury trading program.

E. EPA Applied Appropriate Adjustment Factors for Coal Ranks.

As previously discussed, *supra* § VI(A), a particular state's emission budget is determined by summing hypothetical mercury allocations (based on a calculated adjusted historical baseline heat input), derived using a specified formula, to power plant units located in the State. The State in turn allocates the overall budget to individual sources through allowances. 70 Fed. Reg. 28,623-30. Each power plant's baseline heat input is adjusted to reflect ranks of coal burned. 70 Fed. Reg. 28,612-13. Adjustment factors of 1 for bituminous, 1.25 for subbituminous, and 3 for lignite coals were applied by EPA in determining hypothetical mercury allocations for power plants. *Id.* at 28,622. Application of these adjustment factors in determining hypothetical allocations and ultimately state emission budgets results in a power plant that burns bituminous coal being credited with its actual heat input, whereas a power plant that burns lignite coal would, for purposes of determining state emissions budgets, be credited with three times its actual heat input. Contrary to Petitioners' suggestion, in CAMR EPA only used these adjustment factors to establish state budgets. It did not establish actual allocations for individual facilities. Such unit-specific allocations are in the purview of the State to determine.

“Bituminous Petitioners” are a collection of industry associations involved in the production of bituminous coal, and these associations have a business interest in minimizing costs associated with burning bituminous coal. Accordingly, the Bituminous Petitioners have a strong market incentive to make bituminous coal an attractive fuel for electricity generation, and have attacked EPA's adjustment factors for coal ranks by arguing that those adjustment factors are arbitrary, and unfairly allocate mercury emission allowances to subbituminous and lignite coal burning facilities to the detriment of facilities that burn bituminous coal. [65]

Bituminous Petitioners argue that EPA has not provided adequate support for its coal rank adjustment factors. This is not the case. The record clearly supports EPA's reasonable adjustment factors for coal ranks.

1. EPA's adjustment factors are reasonable.

In the final rule EPA retained adjustment factors previously used in determining state emission budgets. 70 Fed Reg. 28,622. The adjustment factors are supported by the State Budgets TSD. *Id.* (citing State Budgets TSD). The adjustment factors are “based on the expectation that, for different coal ranks, mercury reacts differently to NO_x and SO_2 control equipment.” State Budgets TSD at 2 (JA 1770). EPA examined data in the 1999 power plant Information Collection Request (“ICR”), including data on mercury capture by control figuration and coal rank, data on coal characteristics impacting mercury capture, and mercury emissions and capacity by coal rank, and found that the data supported the adjustment factors. *Id.* at 2-4 (JA 1770-72). The data related to mercury removal rates measured for various coal ranks and control configurations reveal a significant range of mercury capture, and mercury capture rates for bituminous coal are, on average, significantly better than the capture rates measured for subbituminous and lignite coals. *Id.* at 3 (JA 1771). The ICR data related to mercury emissions and capacity by coal rank reveal that emissions for bituminous coal are estimated to be 0.25 pounds of mercury per megawatt of power generated. *Id.* at 4 (JA 1772). Power plants using subbituminous coals emit an estimated 0.37 pounds of mercury per megawatt, and plants using lignite coal emit about 0.65 pounds of mercury per megawatt. *Id.* These numbers support the chosen allocation adjustment because the

0.65 pounds of emissions per megawatt for lignite coal is close to three times the emissions per megawatt for bituminous coal, and the 0.37 pounds of emissions per megawatt for subbituminous coal is greater than 1.25 times that of bituminous coal. *Id.*

Bituminous Petitioners also argue that EPA's allocation methodology must be flawed because lignite- and subbituminous-burning power plants are more likely to receive an allocation that exceeds their actual mercury emissions. Petitioners' position disregards the relative ease with which bituminous-burning power plants can capture their mercury emissions. *See* Reconsideration RTC at 225 (JA 2863). Based on the ICR data, higher levels of mercury capture are expected for bituminous coal-fired power plants than for power plants that burn subbituminous or lignite coals. State Budgets TSD at 3 (JA 1771). EPA conducted an analysis comparing state mercury emission budgets developed using adjusted heat input and state budgets developed using pure (unadjusted) heat input to projected mercury emissions by State and found that, when state budgets are compared to projected emission levels in 2010, when the CAMR Phase I cap is effective, EPA's methodology more closely tracks actual projected emissions levels than Bituminous Petitioners' proposed method. Reconsideration RTC at 234-235 (JA 3872-73).

The fact that the data continues to support EPA's adjustment factors is unsurprising, given that EPA is not seeking to achieve a precise allocation for each power plant but is instead attempting to create an adjustment factor that is "directionally correct," leaving it to the States to determine precise allocations. State Budgets TSD at 2 (JA 1770); 70 Fed. Reg. 28,622. Though final allocations are made by individual States, the rule anticipates that some power plants may control to an emission level below their allocated amounts of allowances and allows those plants to either bank the excess emissions allowances, or sell them on the market. 70 Fed. Reg. 28,622. Similarly, power plants may choose to purchase allowances on the market rather than controlling emissions.

As discussed above, in CAMR the Agency did not allocate any mercury allowances. *Supra* § VI(D). EPA's choice of adjustment factors has no direct impact on the allocation of mercury allowances to CAMR units for purposes of compliance with the program and a State has full flexibility to allocate allowances as it sees fit. Thus, the Bituminous Petitioners' complaint that EPA's adjustment factors unfairly allocate mercury emission allowances is unfounded.

The Court's standard of review under the arbitrary-and-capricious test is one of reasonableness, not perfection. *SeeMotor Vehicle Mfrs. Ass'n v. State. Farm Mut. Auto. Ins. Co.,* 463 U.S at43. Additionally, the Court gives "an extreme degree of deference" to any agency ' 'evaluating scientific data within its technical expertise.' ' *Hüls Am., Inc. v. Browner,* 83 F.3d 445, 452 (D.C. Cir. 1996) (quoting *Int'l Fabricate Inst. v. EPA,* 972-F.2d 384, 389 (D.C. Cir. 1992)). Especially given the complex technical issues at play when determining an appropriate adjustment factor, the exercise of appropriate deference dictates that the Court deny Bituminous Petitioners' petition for review.

2. EPA's CAMR adjustment factors account for factors not at issue in CAIR.

Bituminous Petitioners argue that because EPA, when determining SO_2 allowances for CAIR, rejected allowance allocations by coal rank, EPA should not apply such allowance allocations under CAMR. This argument compares apples to oranges. EPA has developed a sufficient record to justify its decision to apply an adjustment factor when calculating hypothetical allowance allocations under CAMR, as described above. *Supra* § VI(D)(1).

Bituminous Petitioners, when discussing EPA's rationale for declining to employ allowance allocations by coal rank under CAIR, fail to provide the context in which that decision was made. When regulating SO_2 under CAIR, EPA was faced not only with a different pollutant, it was dealing with an entirely different regulatory background that is significantly influenced by Title IV-A of the Act. Title IV-A of the Act, 42 U.S.C. §§ 7651-51***o***, is a statutory attempt to control acid rain. This program controls emissions of SO_2 and NO_x and creates a system of SO_2 emission allowances that be freely traded. Title IV-A, by statute, creates allowances for individual energy producing units. 42 U.S.C. § 7651a(3). These allowances are calculated pursuant to a scheme designed by Congress and do not include adjustment factors of the type used in CAMR. 42 U.S.C. 7651b(a)(1), EPA,

when regulating the' same pollutant under CAIR, reasonably considered statutory and regulatory controls that power plants were already subject to with respect to SO_2, and attempted to preserve the title IV-A allowance allocation approach under CAIR. Reconsideration. RTC at 226 (JA 3864). Mercury emitted from coal-fired power plants, by contrast, is not subject to a previously existing cap-and-trade scheme, much less a scheme designed by Congress rather than the Agency. Accordingly, EPA has broad flexibility when considering the appropriate way in which to regulate emissions of mercury.

Additionally, mercury is an entirely different pollutant that reacts differently to control technology. Power plants that burn bituminous coal are better able to capture their mercury emissions than are power plants, that burn either subbituminous or lignite coals. Legacy Docket A-92-55, II-I-1 (disk 1, attach. 1) (JA 492). When burned, bituminous coals emit less mercury per megawatt of energy generated, based on the 1999 Hg ICR data. *See supra* § VI(E)(1). Because bituminous coals emit less mercury to begin with, and because their mercury emissions are more readily controlled, EPA reasonably granted bituminous coal-burning power plants a proportionately lower hypothetical allocation when determining state emission budgets. Sulfur dioxide does not react to control technology in the same way, and coal rank does not reflect the same disparity in either emissions or application of control technology. *See* 70 Fed. Reg. 28,612-13. Accordingly EPA was reasonable in regulating SO_2. emissions differently.

3. EPA has adequately responded to Bituminous Petitioners, concern-regarding CAMR's Phase 2 adjustment factors.

Bituminous Petitioners argue that EPA's decision to retain adjustment factors under Phase 2 of CAMR must be reversed because EPA has failed to respond “meaningfully” to their comments. This is not the case. A subset of Bituminous Petitioners did argue that adjustment factors were not necessary in Phase 2 of CAMR. CAMR RTC at 9,26 and 9-108 (JA 2073, 2082). In response, EPA incorporated its discussion that justified its decision to finalize the allocation adjustment factors, CAMR RTC at 5-95 - 5-114 (EPA-HQ-OAR-2002-0056-6209 at 5-95 to 5-114)(SJA 56-75), and also referenced the preamble to the final CAMR role and the State Budgets TSD.

The referenced documents discuss EPA's support for the adjustment factors, and satisfy the requirement set Out in 42 U.S.C. § 7607(d)(6)(B). The data reviewed by EPA suggests that mercury emissions from power plants that burn bituminous coal are more easily captured by existing controls, and that bituminous coal-fired plants emits less mercury per megawatt of power generated. *See supra* § VI(D)(1). This fundamental fact is not altered when Phase 2 of CAMR begins. “The failure to respond to comments is significant only insofar as it demonstrates that the agency's decision was not based on a consideration of the relevant factors.” *Thompson v. Clark,* 741 F.2d 401, 409 (D.C Cir. 1984) (internal quotation marks and citation omitted); *accordAmerican Iron & Steel Inst. v. EPA,* 115 F.3d at 1005 (finding comment response sufficient if it “demonstrates that the agency considered the ‘relevant factors' raised by the suggested alternatives”); *Texas Mun. Power Agency v. EPA,* 89 F.3d 858, 876 (D.C. Cir. 1996) EPA's explanation makes it evident that EPA did consider the relevant factors.

F. EPA Established Appropriate Mercury Limitations for Coal-Refuse-Fired Power Plants.

Under CAA section 111, EPA must establish NSPS based on the best system of emission reductions which has been adequately demonstrated. 42 U.S.C. § 7411(a)(1) On this basis, in CAMR EPA set out separate emissions limitations for new, modified, and reconstructed power plants fired with bituminous, subbituminous, and lignite coals, and coal refuse that reflect the use of best demonstrated technology “BDT”. 70 Fed. Reg. 28,615; EPA-HQ-OAR-2002-0056-6721, Revised New Source Performances. Standard Statistical Analysis or Mercury Emissions (“NSPS Memo”) at 1 (JA 3699). For CAMR, the emissions limitation for all coal ranks was based on the 90th percentile mercury reduction (*i.e.*, the control efficiency that the BDT is estimated to achieve 90 percent of the time). 70 Fed. Reg. 28,615; NSPS Memo at 3 (JA 3701). In order to calculate the 90th percentile mercury reduction; EPA relied on an equation that incorporates the 90th percentile average heat content of. the coal burned. NSPS Memo at 6 (JA 3704).

Petitioner ARIPPA, a trade association comprised of coal-refuse-fired power plants, argues that EPA used an incorrect heat content of 11,376 Btu/lb for coal refuse when calculating mercury emission limitations under CAMR. Though ARIPPA-does not challenge EPA's decision to base the emissions limitation on the 90th percentile mercury reduction, ARIPPA claims that EPA failed, to consider relevant data, failed to explain the basis for the application of a 11,376 BTU/lb heat content value to coal refuse, and disregarded the definition of "coal refuse." As discussed below, EPA considered available data, and properly applied a heat content of 11,376 Btu/lb to coal refuse.

1. ARIPPA cites to the incorrect definition of "coal refuse."

ARIPPA, when discussing previous regulatory definitions of the term "coal refuse," cites to a definition set out in 40 C.F.D. § 60.41b. This definition is for industrial boilers. *See* Standards of Performance for Steam Generating Units, 40 C.F.R. § 60.40b. CAMR does not apply to industrial boilers, CAMR applies to electric utility steam generating Units. Thus, the applicable "coal refuse" definition is found in 40 C.F.R. Part 60, subpart Da. *See* Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, 40 C.F.R. § 60.40Da. The definition of "coal refuse" in subpart Da is based on the process by which the coal refuse is produced rather than being based on constituents or parameters of the material. The distinction is important because, although in 40 C.F.R. § 60.41b EPA does establish a maximum heat content value of 6,000 Btu/lb for coal refuse used in industrial boilers, that universe of "coal refuse" is not the same as the universe of "coal refuse" defined in subpart Da. As defined in subpart Da, "coal refuse" includes "waste products of coal mining, physical coal cleaning, and coal preparation operations...containing coal, matrix material, clay, and other organic and inorganic material." 40.C.F.R. § 60.41Da. Because this definition is based on the "production" process rather than the parameters, it includes coal refuse that burns with a maximum heat content value of greater than 6,000 Btu/lb. As demonstrated by data in the CAMR docket, coal reported as being "coal refuse" by the applicable power plants had maximum heat content values that exceeded 6,000 Btu/lb. *See* Legacy docket A-92-55, II-I-8 (JA 494). Accordingly, the heat content used by EPA for coal refuse under CAMR is not inconsistent with the applicable definition.

The differences between definitions are relevant to the respective industry sectors addressed and are, therefore, appropriate. Further, the issue of any definitional differences between various subparts was not raised during the public comment period, and has, thus, been waived. *See* 42 U.S.C. § 7607(d)(7)(B); *Mossville Envtl. Action Now v. EPA*, 370 F.3d at 1238 (strictly interpreting the waiver requirement).

2. EPA properly considered available data when calculating the heat content of coal refuse.

EPA calculated the appropriate achievable mercury emission level for each coal rank, including coal refuse, through statistical analysis. 70 Fed. Reg. 28,615. The heat content value of the fuel input is one of several relevant factors in calculating the control efficiency-based limitation. ARIPPA argues that EPA's calculated heat content for coal refuse is too high,, ultimately subjecting its members to a substantially more stringent mercury emission limitation. ARIPPA Br. at 4. Emissions data supplied by ARIPPA, however, are consistent with the performance standard established by EPA. [66]

When EPA calculated its 90th percentile Btu/lb values for coal refuse, it consistently calculated the value where 90 percent of the Btu/lb values in its sample data would be *less than* the indicated value. EPA used this approach with all coal ranks (bituminous, subbituminous, lignite, and coal refuse). Reconsideration RTC at 273 (JA 3895). ARIPPA has apparently misunderstood EPA's analysis, and has provided the Court with a heat content value for coal refuse of 4,336 Btu/lb based on a calculation where 90 percent of the Btu/lb values would be *greater than* the indicated value. *See* ARIPPA December 19, 2005 Comment at 13 (EPA-HQ-OAR-2002-0056-6529.1 at 13)(JA 2940); ARIPPA Br. at 3, 5. This goes a long way toward explaining the difference between the 90th percentile value calculated by ARIPPA and the significantly higher value calculated by EPA.

Additionally, ARIPPA calculated its heat content value of 4,336 Btu/lb by considering "an analysis of information compiled by ARIPPA's members." ARIPPA Br. at 3. ARIPPA members are coal-refuse-fired electrical generating units in Pennsylvania.

ARIPPA's April 7, 2006 Comment (EPA-HQ-OAR-2002-0056-3698)(JA 2987). In other words, ARIPPA's calculations are based on a limited subset of the available data. EPA's determination that the 90th percentile heat content value of coal refuse (11,376 Btu/lb) is based on nationwide data collected in the ICR. NSPS Memo at 6-7. The ICR consists of data submitted to EPA by power plants nationwide under the authority of CAA section 114, including ARIPPA member data.

ARIPPA additionally argues that EPA failed to properly consider data compiled by ARIPPA members and submitted during reconsideration. ARIPPA Br. at 5. In fact, EPA did review the additional emissions data submitted by ARIPPA. EPA specifically excluded some data for reasons stated on the record, and EPA, where appropriate, incorporated the newly provided data into its analysis to determine the NSPS for coal refuse. Reconsideration RTC at 272-73 (JA 3894-95); NSPS Memo at 3, 11-13 (JA 3701, 3709-11). Specifically, EPA incorporated 23 of 31 additional test runs provided by ARIPPA. NSPS Memo at 12.

Thus, EPA has considered the relevant factors, and the record supports that consideration. *SeeThompson v. Clark,* 741 F.2d at 409 (“The failure to respond to comments is significant only insofar as it demonstrates that the agency's decision was not based on a consideration of the relevant factors.”) Accordingly, EPA properly relied on its calculated heat content of 11,376 Btu/lb for coal refuse.

CONCLUSION

For the foregoing reasons, the petitions for review should be denied.

Footnotes

*Cases chiefly relied upon are marked with an asterisk.

1 Hazardous air pollutants are “pollutants which present, or may present, ... a threat of adverse human health effects ... or adverse environmental effects whether through ambient concentrations, bioaccumulation, deposition, or otherwise.” 42 U.S.C. § 7412(b)(2).

2 A “major source” is any stationary source or group of stationary sources at a single location and under common control that emits or has the potential to emit ten tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. 42 U.S.C. § 7412(a)(1).

3 CAIR was signed on March 15, 2005.

5 Contrary to Petitioners' suggestion (*See* Environmental Br. at 16), EPA did not adopt any different interpretation of the Act in a 1991 Federal Register notice. The 1991 notice is nothing more than a notice of availability of a preliminary draft list of source categories to be regulated under section 112, and a request for information and comment on issues and proposed positions. The notice does not represent or set forth any final EPA position on any issue. After consideration of comments, consistent with its action in the instant rule, EPA concluded in 1991 that it had no authority to regulate power plants if the requirements of section 112(n)(1)(A) had not been met. 57 Fed. Reg. 31,576, 31,584 (July 16, 1992). As to the statement in the 1991 notice concerning section 112(c)(9) and power plants, that statement was made in conjunction with a proposed regulatory option (a proposal to list power plants absent any section 112(n)(1)(A) findings) that EPA did not pursue and that was contrary to the plain language of section 112(n)(1)(A). EPA's final interpretation concerning the relationship of section 112(n)(1)(A) to section 112(c)(9) has been set forth in the Section: 112(n) Rule after notice-and-comment rulemaking.

6 *SeeUARG v. EPA,* No. 01-1074, 2001 WL 936363 (D.C Cir. July 26, 2001) (finding Court lacked jurisdiction to review EPA's initial December 2000 Finding based on 42 U.S.C. § 7412(e)(4)).

7 Webster's dictionary defines the term “appropriate” to mean “especially suitable or compatible.” *Webster's Ninth New Collegiate Dictionary* (1983) at 98. It defines the term “necessary” to mean “absolutely needed.” *Id.* at 790.

8 Government Petitioners cite to *Michigan v. EPA,* 213 F.3d 663 (D.C. Cir. 2000) (*see* Government Br. at 25), but that case involved EPA action under CAA section 110(a)(2)(D), which directs EPA to focus on pollutants that only contribute to a problem. In *Grand Canyon Trust v. FAA,* 290 F.3d 339, 346 (D.C. Cir. 2002), cited by Government Petitioners, the implementing regulations for the National Environmental Policy Act specifically required the FAA to consider cumulatively significant impacts of actions with individually insignificant impacts. CAA section 112(n)(1)(A) does not contain similar language.

9 EPA also explained that its December 2000 Finding was defective to the extent that it relied in part on environmental effects of power plant mercury emissions. 70 Fed. Reg. 16,002/3. Section 112(n)(1)(A) requires EPA to analyze the "hazards to public health" resulting from power plant emissions.

10 Nothing in section 112(n)(1)(A) precludes EPA from considering factors in addition to the section 112(n)(1)(A) study in making an "appropriate and necessary" determination. The statute provides that EPA must consider the study but does not limit EPA to relying *exclusively* upon the study. *Cf.Sierra Club v. EPA*, 325 F.3d 374, 377 (D.C. Cir. 2003) (finding that statute requiring EPA to promulgate rule "based upon" a required study did not require EPA to premise rule exclusively upon results of that study).

11 Once deposited onto land or water, the chemical form of mercury can change into methylmercury, and nearly all of the mercury that accumulates in fish is methylmercury. 65 Fed. Reg. 79,827/1.

12 EPA concluded that freshwater fish (*e.g.*, fish from rivers and lakes) on average has greater concentrations of utility-attributable methylmercury than fish from other sources (*e.g.*, fish from oceans or estuaries), and concluded that individuals who substitute other sources of fish for freshwater fish in their diet can be expected to reduce their exposure to utility-attributable mercury. EPA-HQ-OAR-2002-0056-6303, ("Reconsideration TSD") at 26 (JA 2385); EPA-HQ-OAR-2002-0056-6722, ("Reconsideration RTC")at 63, 131 (JA 3764, SJA 197). With respect to commercial fish, EPA concluded among other things, that (1) the vast majority of commercial fish consumed is not from freshwater sources, (2) the amount of commercial freshwater fish consumed is much smaller than the amount of noncommercial freshwater fish consumed, so including the commercial freshwater pathway in an exposure model would result in a relatively small change in a population level exposure estimate; and (3) it is highly unlikely that the group that consumes the most freshwater fish, subsistence fishers, consumes any significant amount of commercial fish. Reconsideration TSD at 25-26 (JA 2384-85); EPA-HQ-OAR-2002-0056-6186 ("Effectiveness TSD") at 34-35 (JA 1906-07).

13 EPA found that about one percent of total mercury emissions globally are attributable to domestic power plant emissions. 70 Fed. Reg. 16,028/2.

14 To project methylmercury concentrations in fish tissue following implementation of CAIR or CAMR, EPA assumed that a particular reduction in air deposition of mercury in a particular geographic location would result in a proportional reduction in the methylmercury concentration in fish in the same general geographic location. 70 Fed. Reg. 16,019/2.

15 A Reference Dose is an estimate of a daily oral exposure that is likely to be ??

17 Petitioners' position that language in 42 U.S.C. § 7412(c)(1) and 42 U.S.C. § 7412(e)(1) creates a deadline applicable to power plants is misplaced. *See* Environmental Br. at 30. These two provisions do not govern power plants, which are subject to unique treatment as set forth in 42 U.S.C. § 7412(n)(1)(A). Likewise, there is nothing in 42 U.S.C. § 7412(c)(5) that obligates EPA to issue section 112 standards for power plants, much less issue such standards by the end of 2002. *See* Environmental Br. at 30, n.43.

18 The Acid Rain Program requires major reductions of SO_2 and NO_x emissions from power plants. The SO_2 program sets a permanent cap on the total amount of SO_2 that may be emitted by electric power plants. The program is phased in, with the 2010 SO_2 cap set at about one-half of the 1980 emissions from the power sector, 42 U.S.C. § 7651d. Controls used to meet Acid Rain program requirements also reduce hazardous air pollutants. Utility Study at 2-31 to 2-33, 3-12 to 3-14 (SJA 2-4, JA 97-99).

19 Although EPA modeled utility-attributable methylmercury concentrations in 2020 in its hazard analysis, most mercury reductions that will be achieved by CAIR and CAMR will actually be achieved well before 2020. The compliance date for the first phase of NO_x reductions required by CAIR is 2009 and for the first phase of SO_2 reductions required by CAIR is 2010. 70 Fed. Reg. 25,215-16. Most of the relevant mercury reductions resulting from CAIR implementation will occur by 2010. *See* Reconsideration RTC at 51 (JA 3752); EPA-HQ-OAR-2002-0056-6130 ("Air Quality Modeling TSD"), Section V.B.(JA 1758-59).

22 EPA in response to comments also addressed the "NOAA" Study referenced by Physician Intervenors. *See* Physicians' Br. at 13-14; Reconsideration RTC at 143 (JA 3812). EPA noted that the NOAA Study was based on use of a different air quality model, which was not used by EPA because it was a less stable modeling platform than CMAQ and did not account for global sources of mercury or for atmospheric chemistry. EPA additionally noted that, in any event, the level of power plant mercury deposition into the Great Lakes predicted in the NOAA Study and by the CMAQ model used by EPA were similar.

23 In response to comments on reconsideration, EPA applied a 389-grams per day rate for the 99th percentile, after initially applying a 295-grams per day rate. Reconsideration RTC at 71,73 (JA 3772, 3774). The revised rate did not change EPA's conclusions. Reconsideration RTC at 71 (JA 3772).

24 Tribal Petitioners note that the CRITFC Study included consumption rates of individuals who did not consume fish. *See* Tribal Br. at 34, n.6. As EPA noted in response to comments, just seven percent of total study participants did not consume fish, and,

therefore, inclusion of non-consumers in the study did not significantly impact overall consumption rates. Reconsideration RTC at 71 (JA 3772).

25 The cited tables present the expected IDI (*see supra*, at 48-49) at various distributions of fish consumption rates and percentiles of utility-attributable methylmercury concentrations, following implementation of CAIR and CAMR. For example, the table indicates that a subsistence fisher consuming at an average (mean) subsistence rate, and consuming exclusively fish from a location with 95th percentile utility-attributable methylmercury concentrations, would have an expected IDI of 0.66.

26 Environmental Petitioners' argument (*see* Environmental Br. at 34) that EPA failed to assess non-mercury hazardous air pollutants emitted by power plants is also incorrect. In the Section 112(n) Rule, EPA squarely considered and determined that it was not appropriate, and necessary to regulate power plants on the basis of non-mercury emissions. *See* 69 Fed. Reg. 4688-89; 70 Fed. Reg. 62,209/2; 70 Fed. Reg. 16,006-07; EPA-HQ-OAR-2002-0056-6193, *Responses to Significant Public Comments* at 13-21 (JA 1941-49). Environmental Petitioners do not point to any error in EPA's analysis of non-mercury pollutants.

27 EPA estimated the upper-bound monetized value of neurological improvements by quantifying intelligence quotient improvements associated with elimination of all domestic power plant mercury emissions, assuming all persons are exposed above the Reference Dose. Reconsideration TSD at 27-37 (JA 2386-96).

28 EPA explained that regulating mercury emissions under the command-and-control approach set forth in section 112 would be at least as costly as regulating under the market-based cap-and-trade approach of CAMR, and the annualized cost of CAMR was estimated to be approximately $750 million. 70 Fed. Reg. 62,208-09; Reconsideration TSD at 37 (JA 2396). Use of a cap-and-trade program such as that within CAMR to achieve a given level of emission reductions will be predictably less costly than a command-and-control approach to achieve the same level of reductions because economic theory has shown that a marketable permit scheme will produce a least-cost solution for any level of pollution abatement. *See* Reconsideration RTC at 167 (JA 3836).

29 Although Environmental Petitioners do not contest EPA's cost-effectiveness determination, they cite in the background section of their brief to a 2005 study which estimated that economic benefits from a 70 percent cut in power plant mercury emissions would range from $86 million to $4.9 billion. *See* Environmental Br. at 4 & n.9-10 (citing to G. Rice & J.K. Hammitt, "Economic Valuation of Human Health Benefits of Controlling. Mercury Emissions From U.S. Power Plants, ("Harvard Study"). EPA addressed the estimates set forth in the Harvard Study in the rulemaking and explained why EPA's own estimates differed and were superior. *See* Reconsideration TSD at 38-40 (JA 2397-99); 71 Fed. Reg. 33,394/2; Reconsideration RTC at 112, 153, 162, 173 (JA 3795, 3822, 3841, 3842); EPA-HQ-OAR-2002-0056-6289, Stephen Johnson Letter (JA 2355-58). Among other things, the high-end benefit estimates in the Harvard Study largely reflected projected benefits from reduced cardiovascular risk, whereas EPA concluded that substantial uncertainties in available scientific information did not ??

30 EPA reasonably interprets section 112(n)(1)(A) to preclude the consideration of environmental effects unless EPA first finds that hazards to public health are reasonably anticipated to result from utility-attributable emissions remaining after imposition of the requirements of the Act. EPA did not find any hazard to public health here. Reconsideration RTC at 39 (JA 3740).

31 *See* 70 Fed. Reg. 16,030; *see also* 42 U.S.C. § 7411(d)(1)(1988) (precluding standards for existing sources for any air pollutant that, *inter alia*, is "included on a list published under section ... 7412(b)(1)(A) of this title"); *id.* § 7412(b)(1)(A)(1988) ("The Administrator shall ... publish. ... a list which includes each hazardous air pollutant for which he intends to establish an emission standard under this section.").

32 Unless enacted into positive law, the United States Code constitutes only *prima facie* evidence of the laws of the United States while the Statutes at Large constitute *legal* evidence of the laws. Accordingly, in the event of conflict, the language of the Statutes at Large controls over language of the United States Code that has not been enacted into positive law. *See* 1 U.S.C. § 204(a); *see also, e.g., Five Flags Pipe Line Co. v. DOT*, 854 F.2d 1438, 1440 (D.C. Cir. 1988). Because Title 42 of the United States Code has not been enacted into positive law, *see* notes following 1 U.S.C. § 204, the Statutes at Large control in this case. *See generally* 70 Fed. Reg. 16,030.

33 There is no merit to the Petitioners' attempt to invoke a competing canon stating that in the event of conflict between different provisions in the same Act, "the last provision in point of arrangement must control.". Environmental Br. at 24 (citing *Lodge 1858, American Fed'n of Gov't Employees v. Webb*, 580 F.2d 496. 510 & n.31 (D.C. Cir.), *cert. denied*, 439 U.S. 927 (1978)). As EPA correctly explained, this canon is inapplicable here, as it applies to discrete sections of the same Act, not competing amendments to the same section of an Act, as is the case here. 70 Fed. Reg. 16,031-32.

34 Prior to 1990, section 111(d) cross-referenced the list of hazardous air pollutants established pursuant to the then-existing administrative process described in section 112(b)(1)(A), 42 U.S.C. § 7412(b)(1)(A) (1988). In the 1990 amendments to section 112, however, Congress overhauled the listing process for hazardous air pollutants, eliminating section 112(b)(1)(A) and replacing it with an initial statutory list of hazardous air pollutants (new section 112(b)(1)) and other provisions (sections 112(b)(2) and 112(b)(3)) that created a process for revisions and modification to the initial list.

35 As EPA explained, also unlike the corresponding Senate provision, the House version was not described as a "Conforming Amendment," but instead was included with a variety of substantive provisions in a section entitled "Miscellaneous Guidance." *See* 70 Fed. Reg. 16,031 & n.62; 104 Stat. 2465-69 (1990). Petitioners incorrectly describe these "miscellaneous" provisions as "purely ministerial." Environmental Br. at 23. For example, among other things, this section of Public Law No. 101-549 authorized preparation and dissemination of a variety of substantive guidance, reports and data (sections 108(a)-(d)), amended certain deadlines and other substantive criteria pertaining to promulgation of section 111 standards (sections 108(e)(1)&(2)), set forth a variety of new and amended definitions (section 108(j)), amended the stated, findings in section 101 of the Act addressing pollution prevention, 42 U,S.C. § 7401 (section 180(k)), and added certain new public participation requirements to section 307 of the Act, 42 U.S.C. § 7607 (section 108(p)).*See* 104 Stat. 2465-69, Perhaps notably, other sections of the House bill were designated "conforming" or "technical" amendments, and these generally were more ministerial in nature. *See* 2 *A Legislative History of the Clean Air Act Amendments of 1990*, at 3087, 3101 ("1990 Legis. Hist.").

36 *See* H.R. 3030, 101st Cong., at 121, § 108(d) (1989), *reprinted in* 2 1990 Legis. Hist., at 3857 (1993).

37 *See* H.R. Rep. No. 101-490, at 82 (proposed CAA section 112(c)(5)), *reprinted in* 2 1990 Legis. Hist., at 3106; *see also id.* at 2131-32 (comparable provision in S. 1630, as passed by the House).

38 2 1990 Legis. Hist., at 3070; *see also id.* at 1979 (comparable provision in House-passed version of S. 1630).

39 2 1990 Legis. Hist., at 3110-11; *see also id.* at 2148-49 (comparable provision in House-passed version of S. 1630).

40 It also bears emphasizing that the entire concept of "source categories" in section 112 was new in 1990. Prior to 1990, section 112 simply directed EPA to develop a list of hazardous air pollutants and then to establish corresponding emission standards for these pollutants. *See* 42 U.S.C. § 7412(b)(1)(A), (B) (1988).

41 The differences between proposed section 112(m) from the original version of H.R. 3030 and present section 112(n)(1)(A) are minor and are not pertinent here. The most significant difference is that the last sentence of this provision in the House bill *prohibited* EPA from regulating power plants under section 112 *unless* the Agency made an "appropriate and necessary" finding, while the final language of this provision allows such regulation upon such a finding. *Compare* 2 1990 Legis. Hist., at 3945-46, *with* 42 U.S.C. § 7412(n)(1)(A).

42 In support of this latter point, EPA aptly cited the statement of Congressman Oxley explaining that "[t]he conferees agreed to the House provisions because of the logic of basing any decision to regulate on the results of scientific study and because of the emission reductions that will be achieved and the extremely high costs that electric utilities, will face under other provisions of the new Clean Air Act amendments." 136 Cong. Rec. H12911, 12,934 (daily ed. Oct. 26, 1990), *reprinted in* 1 1990 Legis. Hist., at 1416.

43 *See also, e.g.,United States v. Freisinger*, 937 F.2d 383, 388-90 (8th Cir. 1991) (criminal statute allowing prosecution for using or carrying "a" firearm in "any" violent or drug-related crime unambiguously authorizes separate units of prosecution for each firearm possessed).

47 ?? states that, except as otherwise provided for in section 111(h), 42 U.S.C. § 7411(h), which addresses work practice standards and other alternative standards, "nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply, with any new standard of performance." However, under CAA section 111(j), 42 U.S.C. § 7411(j), new sources may seek a waiver of an otherwise applicable standard "to encourage the use of an innovative technological system or systems of continuous emission reduction."

48 As this Court has stressed, CAA section 110 generally leaves to States the choice of which controls are to be applied to particular sources, subject only to an EPA determination of whether the overall state plan maintains or leads to attainment of the NAAQS. *See, e.g., Virginia v. EPA*, 108 F.3d 1397, 1408-10 (D.C. Cir. 1997),. *modified on other grounds*, 116 F.3d 49.9 (D.C. Cir. 1997). Accordingly, this Court has upheld the use of cap-and-trade systems similar to that used in CAMR in cases considering federalism-based challenges to rules addressing multi-state pollution problems under CAA section 110. *SeeMichigan v. EPA*, 213 F.3d at 685-88.

49 In fact, EPA noted that on one prior occasion it had authorized emission trading under section 111(d). *See* 70 Fed. Reg. 28,617.

50 It is worth noting that at least some aspects of *Asarco* may be questionable in light of the Supreme Court's subsequent decision in *Chevron*, and Petitioners never even attempt to reconcile these two cases in their brief. In *Chevron*, the Supreme Court reversed this Court's decision in *NRDC v. Gorsuch*, 685 F.2d 718. (D.C. Cir. 1982), which had relied on *Asarco* and related D.C. Circuit precedent to vacate EPA regulations that had employed the bubble concept for new source review in nonattainment areas *SeeChevron*, 467 U,S. at 841-42 & n.6. As explained in *NRDC*, 685 F.2d at 720, 725-27, this Court's cases had construed the Act to make the bubble concept mandatory for CAA programs designed to maintain air quality but impermissible in programs designed to improve air quality. In *Chevron*, the Supreme Court found that this Court's distinction

was improperly based on its perception of the best reading of the statute, not one that "Congress ever articulated itself." *Chevron*, 467 U.S. at 864; *see also id.* at 865-66.

51 Indeed, consistent with *Asarco*, if an individual existing unit were to undertake a physical change that resulted in an increase in its emission rate it would trigger the new source NSPS, even though it would also be required to hold CAMR allowances covering that increase.

52 To the extent Government Petitioners are attempting to argue that the analytical methodology required under section. 112, 42 U.S.C. § 7412, should somehow inform the selection of a standard of performance under section 111, 42 U.S.C. § 7411, this suggestion is completely inapposite given that Congress established distinct criteria in these two sections. *See generally* Reconsideration RTC at 283-84, 304 (JA 3896-97, 3904).

53 Mercury emission budgets for each State were developed by EPA as follows: EPA used modeling to calculate the amount of mercury emissions from all power plants in the nation, assuming that power plants applied achievable emissions limitations by the 2010 (Phase I cap) and 2018 (Phase II cap) dates. *See* 70 Fed. Reg. 28,621-22. EPA hypothetically allocated a portion of each cap -- that is, an amount of allowances -- to each unit by dividing each unit's "heat input" by the total "heat input" of all units. ("Heat input" is essentially a measure of the amount of energy used by the facility to generate a given amount of electricity. *Id.* at 28,622.) For each State, EPA then summed the amount of hypothetically allocated allowances to determine that State's budget for Phase 1 and Phase 2. *Id.* at 28,621. Given the differing characteristics of various ranks of coal, certain adjustment factors were then applied to this formula based on which subcategory (*e.g.*. bituminous, subbituminous, lignite) the particular power plant was in. *Id.* Certain specific aspects of this methodology, irrelevant to the discussion here, are discussed in more detail below, in our response to the briefs filed by the Development Authority, the Bituminous Petitioners, and ARIPPA.

54 We note that the Court's 1981 decision in *Sierra Club* was considering the 1977 version of the Act as it applied to new rather than existing sources. However, these differences, if anything, make this decision even *more* persuasive precedent on these points, since standards of performance for existing sources, which will have to retrofit their facilities to meet new requirements, necessarily need to be more flexible than standards for new sources, which can be designed to meet new requirements from the outset. In addition, as discussed above, the textual changes Congress made to the section 111(a) definition of "standard of performance" in 1990 further reinforce the conclusion that the reasonableness of standards under this section should be gauged on a national as opposed to source-specific basis.

55 We note that Petitioners have not provided any evidence that any unit can or will increase its emissions. Further, Petitioners have not provided any evidence that any units currently *assumed* to be below the cap level are *in fact* operating below the cap, because emissions data are not available for all units in the United States.

56 *See supra*, at 62-68; *see also, e.g.*, 70 Fed. Reg. 28,631 (explaining that the Agency does not believe that utility hotspots will be an issue after implementation of CAIR, and independently after implementation of CAMR); Reconsideration RTC at 147 (JA 3816) (noting that the "concern that a facility could simply buy [mercury] credits and the hotspot remain reflects a misunderstanding of the cap-and-trade approach" because "[a] facility can buy allowances only if another has reduced emissions ....")

57 The five subcategories are: bituminous coal, subbituminous coal, lignite coal, coal refuse, and integrated gasification combined cycle; or "IGCC." 70 Fed. Reg. 28,612. The subcategories for different coal rank are based on a classification system developed by the American Society of Testing and Materials ("ASTM"). *Id.* As EPA explained, the ASTM system "is structured on a continuum based on a number of characteristics. (*e.g.*, heat content or Btu value, fixed carbon, volatile matter, agglomerating versus non-agglomerating) and provides basic information regarding combustion characteristics." *Id.* at 28,613.

58 *See* 70 Fed. Reg. 62,216 ("It was not our intent, however, to subcategorize on the basis of control technology. Rather, our intent was to recognize that new units located in some areas will have access to an adequate supply of water while units in other areas will not have such access,"); *see also* Reconsideration RTC at 251-52 (JA 3885-86).

59 In their brief, Government Petitioners do not contest EPA's factual conclusion that wet systems are generally not an option or facilities located in relatively dry areas, nor do they explain why they believe EPA was required to deem wet systems to be a "demonstrated" technology within the meaning of CAA section 111(a), 42 U.S.C. § 7411(a), for *all* facilities in the subbituminous new source category. Instead, they simply cite an EPA preamble to a role under CAA section 112, 42 U.S.C. § 7412, as support for the general proposition that subcategorization by control technology "leads to situations where floors are established based on performance of sources that are not the best performing." Government Br. at 31 (quoting 69 Fed. Reg. 394, 403 (Jan. 5, 2004)). As noted above, however, this is not what EPA did here.

60 Although the Petitioners do not raise this issue, EPA considered and fully responded to comments identifying specific instances where facilities in "dry" areas were currently using "wet" systems. *See* Reconsideration RTC at 251 (JA 3885). The Agency explained, among other things, that regardless of these isolated *existing source* examples, given the escalating

demand on Western water supplies, it will be increasingly more difficult for *new* sources in such areas (which are the sources to which this variable standard applies) to obtain sufficient water supplies to facilitate use of wet systems. *Id.*

61 *See* 3 1977 Legis. Hist., at 509 (Conference Committee Report noting States' authority to "decide[] to be more stringent" in adopting section 111(d) standards); *id.*, 4 1977 Legis. Hist. at 2662 (House Committee Report similarly noting that States may "decide[] to adopt and enforce more stringent standards").

63 Additionally, Development Authority did not raise its CAA section 111(d) argument in its comments, thus this argument has been waived. *See* 42 U.S.C. § 7607(d)(7)(B); *Mossville Environmental Action Now v. EPA*, 370 F.3d 1232, 1238 (D.C. Cir. 2004) (strictly interpreting the waiver requirement).

64 Development Authority also argues that by relying on actual data, as opposed to projected emissions data, EPA failed to meet the strictures of section 111 and instead effectively imposed a section 112 standard because it failed to consider costs. Nothing in section 111 requires that EPA consider cost to an *individual* unit in establishing an overall section 111 standard and, in setting this standard EPA clearly took cost into account.

65 This is contrary to EPA's Regulatory Impact Analysis that projects continued growth of bituminous coal use under CAMR. Reconsideration RTC at 225 (JA 3863).

66 Although EPA does not have actual coal refuse emissions data in the requisite format (*i.e.*, output-based, lb/MWh), input-based (*i.e.*, lb/TBtu) emissions data provided by ARIPPA are consistent with the lb/TBtu value EPA used in establishing the output-based NSPS value. *See* EPA-HQ-OAR-2002-0056-6698.1, .2, .4, .5, .7, .8., and .9 (JA 2989-3163, 3207-3487; NSPS Memo at 10 (JA 3708).

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NOT YET SCHEDULED FOR ORAL ARGUMENT

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 05-1097 (and consolidated cases) COMPLEX

STATE OF NEW JERSEY, *et al.*
Petitioners,
v.
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,
Respondent.

On Petition for Review of Final Rules of The
United States Environmental Protection Agency

JOINT BRIEF OF STATE RESPONDENT-INTERVENORS, INDUSTRY RESPONDENT-INTERVENORS, AND STATE AMICUS

The States of North Dakota, Alabama, Indiana, Nebraska, South Dakota, Wyoming, and Industry Respondent-Intervenors Utility Air Regulatory Group, Edison Electric Institute, Duke Energy Indiana, Inc., Duke Energy Kentucky, Inc., Duke Energy Ohio, Inc., PPL Corporation, PSEG Fossil LLC, NRG Energy, Florida Power and Light, and National Mining Association, and State Amicus West Virginia, Department of Environmental Protection

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For the National Mining Association

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF NEW JERSEY, et al.	)	
	)	
Petitioners,	)	
v.	)	**No. 05-1097 and**
	)	**Consolidated Cases**
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,	)	
	)	
Respondent.	)	

CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES

Pursuant to Circuit Rule 28(a)(1), the undersigned counsel for Respondent-Intervenor the Utility Air Regulatory Group ("UARG") submits this certificate as to parties, rulings and related cases.

A. PARTIES AND *AMICI*

All parties and *amici* are listed in the brief of Government Petitioners State of New Jersey, *et al.* except for Intervenors State of Maryland, WEST Associates, and National Mining Association and for Amicus State of West Virginia, Department of Environmental Protection.

Rule 26.1 Disclosure Statements:

i) UARG is a not-for-profit association of individual electric generating companies and national trade associations that participates collectively in administrative proceedings, and in litigation arising from those proceedings, that affect electric generators under the Clean Air Act. UARG has no outstanding shares or debt securities in the hands of the public and has no parent company. No publicly held company has a 10% or greater ownership interest in UARG.

ii) Duke Energy Indiana, Inc., Duke Energy Kentucky, Inc., and Duke Energy Ohio, Inc., together f/k/a Cinergy Corporation, are publicly-held companies that are the operating business

units of Duke Energy Corporation. Duke Energy Indiana, Inc. generates, transmits, distributes, and sells electricity in the State of Indiana. Duke Energy Kentucky, Inc. generates, transmits, distributes, and sells electricity in the State of Kentucky. Duke Energy Ohio, Inc. generates, transmits, distributes, and sells electricity in the State of Ohio. Each company is wholly-owned by their parent company, Duke Energy Corporation (a Delaware corporation). No other publicly-held entity owns 10% or more of any of the Petitioners' stock.

iii) PPL Corporation ("PPL") is a corporation organized under the laws of the Commonwealth of Pennsylvania. There is no parent corporation or publicly-held corporation that owns 10% or more of the outstanding units of PPL.

iv) PSEG Fossil is a limited liability company organized under the laws of the State of Delaware. PSEG Fossil is wholly-owned by PSEG Power LLC.

v) Florida Power & Light Company ("FPL") is a corporation organized under the laws of the State of Florida. FPL is the principal subsidiary of FPL Group, Inc. ("FPL Group"), an investor-owned company trading on the New York Stock Exchange. FPL Group owns 100% of FPL's stock.

vi) NRG Energy, Inc. ("NRG") is a corporation organized under the laws of the State of Delaware. There is no parent corporation or publicly-held corporation that owns 10% or more of the outstanding units of NRG.

vii) The National Mining Association ("NMA") is an incorporated national trade association whose members include the producers of most of America's coal, metals, and industrial and agricultural minerals; manufacturers of mining and mineral processing machinery, equipment, and supplies; and engineering and consulting firms that serve the mining industry.

NMA has no parent companies, subsidiaries or affiliates that have issued shares or debt securities to the public, although NMA's individual members have done so.

viii) The Edison Electric Institute ("EEI") is a nonprofit trade association that represents investor-owned electric utility companies. EEI has no parent company, subsidiaries or affiliates that have issued shares or debt securities to the public.

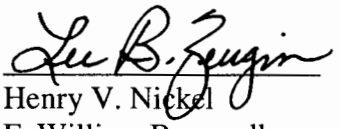
B. RULINGS UNDER REVIEW

References to the final actions by EPA at issue in these consolidated cases appear in the brief of Government Petitioners.

C. RELATED CASES

The matters under review have not been previously heard in this or any other court. There are no related cases pending before this court.

Respectfully submitted,



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Counsel for the Utility Air Regulatory Group
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TABLE OF CONTENTS

TABLE OF AUTHORITIES

FEDERAL CASES

FEDERAL STATUTES

Clean Air Act ("CAA"), 42 U.S.C. § 7401. *et seq.*

* Cases chiefly relied upon are marked with an asterisk

FEDERAL REGULATIONS

FEDERAL REGISTER

* Cases chiefly relied upon are marked with an asterisk

LEGISLATIVE HISTORY

* Cases chiefly relied upon are marked with an asterisk

GLOSSARY OF TERMS AND ABBREVIATIONS

CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
EGU	Electric Generating Unit
EPA	United States Environmental Protection Agency
HAP	Hazardous Air Pollutant
Hg	Mercury
MACT	Maximum Achievable Control Technology
Mercury Study	Mercury Study to Congress (Dec. 1997)
Ni	Nickel
RIA	Regulatory Impact Analysis
RfD	Reference Dose
SCR	Selective Catalytic Reduction Control
UARG	Utility Air Regulatory Group
Utility Study	Study of Hazardous Air Pollutant Emissions from Electric Steam Utility Units -- Final Report to Congress (Feb. 1998)

PERTINENT STATUTES AND REGULATIONS

All applicable statutes, regulations and legislative history are contained in the briefs of Respondent U.S. Environmental Protection Agency ("EPA") and of Petitioner State of New Jersey, and to the extent not therein, are set forth in the addendum to this brief.

ISSUES PRESENTED FOR REVIEW

1. Did EPA Administrator Browner's December 2000 notice purporting to list electric utility generating units ("EGUs") under §112(c) limit the discretion of future EPA Administrators to determine under §112(n)(1)(A) whether EGUs should be regulated?

2. Is EPA's May 2005 rulemaking determination that it is neither "appropriate" nor "necessary" to regulate EGU mercury emissions under CAA §112 lawful and supported by the record?

3. Is CAMR lawful and supported by the record?

STATEMENT OF THE CASE

When Congress overhauled the Clean Air Act ("CAA" or "Act") in 1990, it had a clear vision for controlling hazardous air pollutant ("HAP") emissions from EGUs and from other sources. In general, Congress provided that §112 regulation begins with categorizing sources, then moves to rulemakings to set stringent technology-based standards, and then further rulemakings to address any unacceptable residual risk. In contrast, Congress concluded that this general framework did not make sense for EGUs.[1] Congress knew that other parts of the 1990

[1] *See* 136 Cong. Rec. S16899 (Oct. 27, 1990) (Senator Burdick noted: "a full control program in the United States requiring dry scrubbers and baghouses to control mercury emissions from coal-fired EGUs would double the costs of acid rain control with no expectation of perceptible improvement in public health"); 136 Cong. Rec. H12934 (Oct. 26, 1990) (Rep. Oxley stated: "if the Administrator regulates any [EGUs], he may regulate only those units that he determines -- after taking into account compliance with all provisions of the act and any other

Amendments, notably the Acid Rain program, would impose substantial compliance requirements on EGUs that would reduce indirectly EGU HAP emissions. As a result, information on the public-health implications of any remaining HAP emissions, as well as the efficacy and costs of further control, required further study.[2] Consequently, Congress did not apply the new HAP-control framework to EGUs, but rather asked EPA to decide whether to regulate EGU HAP emissions after imposition of the other CAA requirements. This broad delegation took the form of CAA §112(n)(1)(A), which requires EPA to study EGU HAP emissions and to determine if further regulation is "appropriate and necessary."

The two central issues in this case relate to how EPA carried out this broad delegation of authority under §112(n)(1)(A). The first is whether certain findings made by EPA's Administrator in December 2000, in the closing hours of the Clinton Administration, precluded subsequent Administrators from exercising the discretion Congress delegated EPA in §112(n). The second is whether the subsequent interpretations and policy judgments that EPA made in carrying out those tasks were reasonable and adequately supported.

As the long history of EPA's efforts to implement §112(n)(1)(A) shows, the December 2000 finding did not limit the discretion of future Administrators under §112(n). Moreover, EPA's subsequent rulemaking actions were reasonable and fully supported by one of the most extensive records ever compiled under the CAA.

A. The Clean Air Act

Section 112 was added to the CAA in 1970. The 1970 Act required EPA to make a risk-based determination in order to regulate substances as HAPs: EPA may regulate substances

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Federal, State, or local regulations and voluntary emission reductions -- have been demonstrated to cause a significant threat of adverse effects on the public health").

[2] *See id.*

"reasonably … anticipated to result in an increase in mortality or an increase in serious … illness," to a level that protects public health with an "ample margin of safety." CAA §112(a)(1). Under this provision, EPA regulated a number of HAPs emitted from industrial source categories other than EGUs. *See* 40 CFR Part 63.

As for EGUs, EPA found that the combustion of fossil fuels produces extremely small releases of a broad variety of substances that are present in trace amounts in fuels and that are removed from the gas stream by control equipment installed to satisfy other CAA requirements. EPA found that these HAP releases did not pose hazards to public health. *See* 48 Fed. Reg. 15,076, 15,085 (1983) (radionuclides). In the case of mercury specifically, EPA found that "coal-fired power plants … do not emit mercury in such quantities that they are likely to cause the ambient mercury concentration to exceed" a level that "will protect the public health with an ample margin of safety." 40 Fed. Reg. 48,297-98 (1975) (mercury); 52 Fed. Reg. 8,725 (1987) (reaffirming mercury conclusion).

In 1990, Congress expressed concern that the risk-based approach to HAP regulation of the 1970 CAA was time-consuming and expensive to implement for non-EGUs. *See* S.Rep. No. 101-228, at 131-33 (1989), 1990 U.S. Code Cong. & Admin. News at 3385, 3516-18. Congress therefore designated 189 chemicals as HAPs under §112(b) and instructed EPA in §112(c) to list categories of "major" stationary sources of HAP emissions for the development of control technology-based emission standards under §112(d). These technology-based standards are referred to as "maximum achievable control technology" or "MACT" standards and are based on the emission reductions achieved by the best controlled similar sources. 42 U.S.C. §7412(d). To de-list a category or subcategory of major sources from this technology-based program, EPA must make a risk-based determination. CAA §112(c)(9). For non-EGUs, therefore, the 1990

CAA changed the risk-based determination from a threshold for HAP regulation to a criterion for "de-listing" a major source category.

By contrast, in §112(n)(1)(A), Congress instructed EPA *not* to regulate EGU HAP emissions until it completed a study of the "hazards" to public health "reasonably anticipated to occur" as a result of EGU HAP emissions, and after considering the impact of *"imposition of the requirements of this Act"* on those emissions. As part of that evaluation, Congress also directed EPA to "develop and describe" *"alternative control strategies"* (which EPA has always understood to include emission trading strategies[3]) for any HAP emissions that "may warrant regulation under this section." Finally, Congress told EPA to regulate HAP emissions from EGUs under §112 only to the extent it found, after rulemaking, that regulation was *"appropriate and necessary after considering the results of the study"* required by §112(n)(1)(A).

In implementing provisions such as §112, CAA §307(d) provides rulemaking procedures that apply in lieu of the Administrative Procedures Act rulemaking requirements. In §307(d)(1)(C), Congress directed that these procedures "appl[y] to…any regulation under section 112…(n)."

Apart from §112, §111 is one of a number of other CAA programs used to regulate EGU emissions. *See, e.g.,* 40 C.F.R. Part 60, Subparts D and Da. Section 111 standards for EGUs cover substances such as particulate matter that is comprised, in part, of listed HAPs, and substances such as sulfur dioxide and nitrogen oxides whose control results in reduction of HAPs. *See* 48 Fed. Reg. at 15,085. Section 111 authorizes EPA to establish "standards of performance," 42 U.S.C. §7411(a)(1), for new and existing sources in source categories that "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to

[3] *See* 65 Fed. Reg. 79,830 (a trading approach will be considered when standards are developed).

endanger public health or welfare," 42 U.S.C. §7411(b)(1)(A). Standards of performance must reflect "the degree of emission limitation achievable through application of *the best system* of emission reduction." 42 U.S.C. §7411(a)(1) (emphasis added). Recognizing the potential overlap between §111 and §112 regulation, Congress directed that the Administrator may prescribe §111 standards of performance for existing sources only for an "air pollutant … which is *not … emitted from a source category which is regulated under §112 of this title,*" 42 U.S.C. §7411(d)(1) (emphasis added).[4]

In sum, EPA can regulate EGU HAP emissions under §112 *only* if it determines, *after rulemaking*, that regulation of specific HAP emissions is "appropriate and necessary" to avoid "hazards" to "public health," and only after considering the impact of other CAA requirements and "alternative control strategies." Furthermore, regulation of a source category cannot occur simultaneously under §111 and §112; EPA must choose one or the other.

B. Mercury

Mercury is a naturally occurring element in the Earth's crust that is released into the environment as a result of both natural processes, such as volcano eruptions and reemission from oceans and soils, and manmade processes such as gold and ore mining, municipal and medical waste incineration, fossil fuel combustion, and chlorine manufacturing. EPA has estimated that total global emissions of mercury are about 5,000 tons per year: 1,000 tons from natural sources, 2,000 tons from manmade sources and 2,000 tons from release of mercury into ambient air that has been deposited on soil or in water. 69 Fed. Reg. 4,658. Mercury is a global pollutant. Much

[4] The statutory language of §111(d)(1) is confused because the 1990 CAA contained two different and conflicting amendments that were included in the legislation signed by the President. The House-created language is quoted above. EPA's brief explains how EPA reconciled these two amendments. *See* EPA Br. at 98-118.

of the mercury emitted enters the global pool where it circulates in the atmosphere for up to one year before depositing on soil or in water.[5]

EPA estimates that U.S. coal-fired EGUs emit about 45 tons of mercury annually, or about 1% of worldwide mercury emissions. Furthermore, EPA estimates that only about 30% of EGU mercury emissions (13.5 tons) deposits in the U.S. (By comparison, about 75% of the mercury that deposits in the U.S. originates from sources outside the U.S.) As a result, U.S. coal-fired EGUs contribute only about 8% of the total annual mercury deposited across the U.S. *See* 70 Fed. Reg. 16,019.

In nature, mercury is found in elemental, organic (methylmercury) and inorganic forms. 69 Fed. Reg. 4,657. The primary route of human mercury exposure is by consumption of methylmercury in fish. 69 Fed. Reg. 4,658. Methylmercury is principally formed by microbial action in the top layers of sediment in water bodies, after mercury has precipitated from the air and deposited into those waters. Once formed, methylmercury bioaccumulates in the aquatic food chain, ultimately reaching large predator fish consumed by humans. *See* Utility Study at 7-1 (JA100).

Fossil fuel combustion by EGUs produces trace amounts of three forms of mercury: elemental, particulate, and gaseous ionic. 70 Fed. Reg. 16,011. EGUs do not produce or emit organic forms of mercury, like methylmercury. The mercury deposited in the U.S. as a result of EGU emissions must be transformed in the environment into methylmercury before it can enter the food chain and contribute to human exposure. As EPA recognizes, only a fraction of the 13.5

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[5] *See* Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units -- Final Report to Congress, at 7-7 (Feb. 1998)(the "Utility Study") (Docket No. A92-55-I-A-90)(SJA325).

tons of EGU mercury emissions deposited in the U.S. actually enters water bodies, and only a fraction of that deposition is transformed into methylmercury.[6]

C. EPA's §112(n)(1)(A) Rule

Shortly after enactment of the 1990 CAA, EPA began updating information on the types and amounts of HAPs emitted from the combustion of coal, oil and gas by EGUs. EPA also collected information on the health effects of those HAPs, and conducted modeling to determine how those emissions may affect public health. The products of these efforts were reported in the Mercury Study[7] and the Utility Study, published in December 1997 and February 1998, respectively. The Utility Study did not contain a §112(n)(1)(A) regulatory determination whether regulation of certain HAPs under §112 was "appropriate and necessary." Utility Study, at ES-1 (JA65). Instead, EPA stated that it "believes that mercury from coal-fired utilities is the HAP of greatest potential concern and merits additional research and monitoring" to inform a regulatory determination. Utility Study, at ES-27(JA91). EPA also noted a "potential concern" about nickel emissions from oil-fired plants, but noted that "significant uncertainties" exist about the form and health effects of those emissions.

Following issuance of the Utility Study, EPA undertook several efforts to advance its understanding of mercury health effects and of the quantity and form of mercury emissions from

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[6] *See* Regulatory Impact Analysis, Section 3 (EPA-HQ-OAR-2002-0056-6194)(JA1964-2022).

[7] Mercury Study to Congress (Dec. 1997) (the "Mercury Study") (Docket No. A92-55-I-A-125). The Mercury Study is a "state-of-the-science" report focused on mercury emissions from all sources, the health and environmental effects of those emissions, and technologies for controlling mercury. 42 U.S.C. §7412(n)(1)(B).

coal-fired EGUs.[8] At Congress' direction, EPA asked the National Academy of Sciences ("NAS") to review the toxicological effects of methylmercury and to make recommendations regarding an appropriate reference dose ("RfD"). The NAS National Research Council panel found that EPA's RfD for methylmercury was "scientifically justified."[9] EPA also issued two information collection requests to EGUs. The first required all coal-fired EGUs to collect coal samples throughout 1999 and to analyze those samples for mercury content. The second required approximately 80 EGUs to conduct stack sampling of their mercury emissions over a three-day period. EPA never undertook a corresponding effort to obtain information about nickel emissions from oil-fired EGUs, the nickel species emitted, or the risks such emissions might represent.

On December 14, 2000, days before the Clinton Administration left office and well before EPA could complete the data collection and research it said was necessary to make a §112(n)(1)(A) determination, then-departing Administrator Browner published, without any rulemaking, a "notice of regulatory finding." This notice announced her "conclusion" that regulation of mercury emissions from coal-fired EGUs and nickel emissions from oil-fired EGUs was "appropriate and necessary" under §112. 65 Fed. Reg. 79,825 (Dec. 20, 2000). Because necessary research had not been completed, the notice neither described the increment of emissions whose control was "necessary and appropriate" under §112, nor the "alternative control strategies warranted to address those emissions under this section." Indeed, Administrator Browner acknowledged that EPA could not at that time quantify the amount of

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[8] In the Utility Study, EPA identified eleven areas where additional mercury research was needed. Utility Study, at 14-8 and 14-9 (SJA326-327). EPA's post-Utility Study work focused on four of those areas of scientific need.

[9] National Research Council, *Toxicological Effects of Methylmercury,* at 9 (2000) (Docket No. A92-55-I-A-137) (SJA329).

methylmercury (the form of mercury of health concern) in U.S. fish attributable to mercury emissions from domestic coal-fired EGUs. 65 Fed. Reg. 79,827.

Administrator Browner explained "it is unnecessary to solicit...public comment on today's finding [because]...[t]he regulation developed subsequent to the finding will be subject to public review and comment." 65 Fed. Reg. at 79,831, cols. 1-2. In that future rulemaking, she explained, EPA would consider alternative control strategies, including "economic incentives such as emissions trading." *Id.* at 79,830.

UARG, one of the parties on this brief, sought review of the December 2000 notice in this Court.[10] UARG planned to argue that Administrator Browner's "appropriate and necessary" finding was not factually justified and that EPA had violated CAA §§112(n)(1)(A) and 307(d) by issuing the finding and by purporting to list EGUs under §112(c) as a "major" source category based on that finding. In response, EPA filed a motion to dismiss advising this Court that "[b]ecause the decision to add coal and oil fired electric utility steam generating units to the source category list is *not yet final agency action*, it will be among the matters subject to further comment in the subsequent rulemaking."[11] On July 26, 2001, this court granted EPA's motion to dismiss.

Following the December 2000 notice, EPA conducted a comprehensive §112(n)(1)(A) rulemaking. In that rulemaking, EPA considered a number of regulatory options, including: (1) no further regulation of EGU mercury emissions, or (2) adoption of legislative rules regulating EGU mercury emissions under §112(d), or (3) adoption of legislative rules under §112(n)

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[10] *Utility Air Regulatory Group v. EPA*, No. 01-1074 (2001).

[11] EPA's Motion to Dismiss, at 9 (emphasis added); *see also* EPA's Reply in Support of Motion to Dismiss, at 4 ("the entire predicate for EPA's finding determination and listing decision (both legal and factual) is susceptible to further comment and administrative review"); 70 Fed. Reg. 15,996.

addressing any EGU emissions that are "appropriate and necessary" to regulate, or (4) adoption of legislative rules under other CAA sections that make further controls inappropriate and unnecessary under §112.[12] EPA also completed extensive scientific and technical studies to address the areas of research need identified in the Utility Study.[13] Commentors submitted detailed technical information on EGU mercury emissions and on the health consequences of those emissions.[14] The result is a rulemaking record that is the most detailed record ever developed by EPA to support regulatory action under §112.

In particular, EPA conducted extensive modeling to analyze how changes in mercury emissions from coal-fired EGUs would affect U.S. mercury deposition and methylmercury levels in fish for a range of cases.[15] EPA's analyses included an alternative scenario assuming zero mercury emissions from all EGUs. The modeling showed that total mercury deposition in the U.S. is not significantly impacted by mercury deposition from EGUs, and that EGUs contribute a "relatively small percentage" to fish tissue methylmercury levels in the U.S. 70 Fed. Reg. 16,019-20. More importantly, the modeling showed that the implementation of other requirements of the Act produces the vast majority of the reductions in U.S. mercury deposition and in U.S. methylmercury levels in fish tissue that can be achieved by controlling mercury

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[12] *See* 69 Fed. Reg. 4,652.

[13] EPA's factual results and conclusions are presented in a series of technical support documents ("TSDs") and other technical reports contained in the rulemaking record, and numbering several thousand pages.

[14] *See, e.g.,* UARG Mercury Comments (EPA-HQ-OAR-2002-0056-2922); UARG NODA Comments (EPA-HQ-OAR-2002-0056-5497); EPRI Mercury Comments (EPA-HQ-OAR-2002-0056-2578); EPRI NODA Comments (EPA-HQ-OAR-2002-0056-5502).

[15] EPA's modeling is summarized in the preamble to the §112(n)(1)(A) rule. 70 Fed. Reg. 16,011-25.

emissions from coal-fired EGUs.[16] Thus, EPA concluded "[t]hat modeling reveals the implementation of section 110(a)(2)(D), through CAIR, would result in a level of [mercury] emissions from Utility Units that would not cause hazards to public health." 70 Fed. Reg. 16,004.

On March 29, 2005, EPA concluded its §112(n)(1)(A) rulemaking. Regarding mercury, EPA found that "[b]ecause this new information demonstrates that the level of Hg [mercury] emissions projected to remain 'after imposition of' section 110(a)(2)(D) [*i.e.*, CAIR] does not cause hazards to public health, we conclude that it is not appropriate to regulate coal-fired Utility Units under section 112 on the basis of Hg emissions." *Id.* at 16,004. EPA similarly concluded that it is not appropriate or necessary to regulate nickel from oil-fired EGUs, because it "do[es] not anticipate that the remaining level of utility nickel emissions will result in hazards to public health" based on "(1) the significant reduction in total nationwide inventory of oil-fired Utility Units; and (2) the changing fuel mixtures being used at the remaining units." *Id.* at 16,007-08. EPA therefore removed EGUs from the §112(c) list because the December 2000 notice "lacked foundation" and because §112 regulation was neither appropriate nor necessary. *Id.* at 15,994.

D. The Clean Air Mercury Rule ("CAMR")

On the same day EPA issued its §112(n)(1)(A) rule, it decided to regulate further mercury emissions from coal-fired EGUs under CAA §111. 70 Fed. Reg. 28,606. EPA decided *not* to regulate oil-fired EGUs under §111 on the ground that "there are fewer oil-fired units in operation and that Ni [nickel] emissions had diminished since the Utility Study." *Id.* at 28,611.

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[16] *See id.* The control equipment installed to meet EPA's "Clean Air Interstate Rule" ("CAIR") and other CAA requirements will remove most of the ionic and particulate mercury presently emitted from EGUs -- the two forms of mercury that can deposit in the U.S. (elemental mercury generally does not deposit in the U.S. but enters the global pool). *See* Effectiveness TSD, at 1 (EPA-HQ-OAR-2002-0056-6186)(JA1873).

EPA interpreted the term "standard of performance" in §111(a) to include emission trading systems and determined that the "best system of [mercury] emission reduction" for existing EGUs was a national cap-and-trade program that ensured that (i) mercury emissions were limited in accordance with the "best system" of emissions control, and (ii) that mercury emissions from coal-fired EGUs -- both existing and new -- were capped so total emissions could never increase in the future as new facilities were built to meet increased electricity demand. 70 Fed. Reg. 28,616 col. 3, 28,617 col. 2.

CAMR sets emission limits for new EGUs and establishes a nationwide cap-and-trade program for mercury emissions from *all* coal-fired EGUs. Total mercury emissions from all EGUs are capped at 38 tons per year ("tons/yr") in 2010 and 15 tons/yr beginning in 2018. CAMR's cap-and-trade program is implemented through state plans developed under §111(d). Based on the extensive analyses performed for the §112(n)(1)(A) regulatory determination, EPA found that the additional mercury controls required by CAMR would result in "relatively small" additional reductions in mercury deposition in the United States when compared to the imposition of other CAA requirements, including CAIR, and that going beyond CAMR to zero emissions would produce little or no health benefits. 70 Fed. Reg. 16,019-20.

E. Petitions for Reconsideration

After EPA published its §112(n)(1)(A) rule and CAMR, two petitioners in this case filed petitions seeking reconsideration of both CAMR and EPA's §112(n)(1)(A) rule regarding coal-fired EGU mercury emissions and oil-fired EGU nickel emissions.[17] On October 28, 2005, EPA agreed to reconsider these decisions. EPA requested additional comment on several aspects of its §112(n)(1)(A) rule, including its legal interpretation of §112(n)(1)(A), the detailed technical

[17] No petitioner has challenged EPA's decision not to regulate EGU nickel emissions under §111.

and scientific analyses of the impact of EGU mercury emissions on public health, and information on oil-fired EGU nickel emissions. 71 Fed. Reg. 33,390.

After considering the petitions for reconsideration and the additional comments received in response, EPA found no reason to make any substantive revisions to its §112(n)(1)(A) rule or CAMR. 71 Fed. Reg. 33,388. EPA's detailed 306-page response to comments[18] addresses, among other issues, petitioners' claims (1) that mercury hot spots exist or will be created by EPA's regulatory actions,[19] (2) that EPA analyzed only mercury exposures resulting from the self-caught freshwater fish exposure scenario,[20] (3) that EPA had failed to consider the background levels of mercury (even though EPA analyzed the case where EGU mercury emissions were reduced to zero and found that "virtually none of the risks to public health stemming from the global pool would be reduced"),[21] (4) that EPA misused certain surveys of tribal fish consumption,[22] and (5) that a small group of tribe members were theoretically exposed to methylmercury levels above the RfD.[23]

SUMMARY OF ARGUMENT

EPA's §112(n)(1)(A) rule and CAMR are the culmination of the most extensive §112 rulemaking ever undertaken. Congress treated EGUs differently from all other sources under

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[18] Response to Comments: Reconsideration of Final Section 112(n) Revision Rule and CAMR, May 31, 2006 (EPA-HQ-OAR-2002-0056-6722). Petitioners make *no mention* of EPA's Response to Comments nor do they explain why EPA's rejection of their factual claims in that document was unreasonable or made without considering their claims.

[19] *Id.* at 134-52 (JA3803-21).

[20] *Id.* at 118-24 (JA3796-802).

[21] *Id.* at 41-46 (JA3742-47).

[22] *Id.* at 66-78 (JA3767-79).

[23] *Id.* (JA3776).

§112, requiring EPA to study EGU HAP emissions to determine whether further §112 regulation of EGUs was "appropriate" and "necessary." EPA's March 2005 decision that §112 regulation of EGUs is neither "appropriate" nor "necessary" comports with the language of §112(n)(1)(A) and is supported by an extensive factual record.

Petitioners' principal challenge to EPA's §112(n) rule rests on a faulty claim that a December 2000 notice and listing of EGUs as a major source category under §112(c) bound all subsequent EPA Administrators to regulate EGUs under the §112(d) MACT provisions. EPA has consistently maintained that the December 2000 notice was not final agency action and that parties had the right to comment on the legal and factual bases for that notice during subsequent rulemaking proceedings. When EPA completed its §112(n) rulemaking and issued its final determination that regulation of EGUs under §112 was not "appropriate" or "necessary," EPA was required to withdraw the non-final listing of EGUs under §112(c) because the factual predicate for §112 regulation no longer existed.

As explained in detail in EPA's brief, CAMR is consistent with the language of §111. Petitioners primary factual challenge to CAMR, namely that mercury "hot spots" may be created, was fully considered and rejected by EPA during the rulemaking process.

ARGUMENT

I. EPA's May 2005 §112(n)(1)(A) Rule Is Lawful and, as a Result, There Is No Basis for Including EGUs on the §112(c)(1) List.

In the §112(n) rule, EPA found that it was neither "appropriate" nor "necessary" to regulate any EGU HAP emissions (including mercury and nickel) under §112. While petitioners sought administrative reconsideration of EPA's §112(n)(1)(A) determination not to regulate oil-fired EGU nickel emissions, they did not seek review of, or otherwise challenge, EPA's decision

regarding nickel.[24] Petitioners challenge *only* EPA's decision not to regulate coal-fired EGU mercury emissions under §112, and they further challenge the §111 standard of performance EPA promulgated for EGU mercury emissions. For the reasons discussed below, Petitioners' arguments are inconsistent with the CAA and with basic tenets of administrative law.

A. A §112(n)(1)(A) Determination Is a Precondition to Regulation of EGU HAP Emissions Under §112.

In CAA §§112(n)(1)(A) and 307(d), Congress provided that EGUs may only be regulated under §112 following a notice and comment rulemaking that addresses whether it is "appropriate and necessary" to regulate HAP emissions "after imposition of the requirements of this Act," and after consideration of "alternative control strategies for any emissions that warrant regulation under this section." No one disputes that no §112(n) rulemaking was completed, much less conducted, when Administrator Browner purported to list EGUs under §112(c)(1).

According to Petitioners, however, the mere issuance of the non-final December 2000 notice subjected EGUs to the regulatory regime that Congress crafted for non-EGU major source categories, and precludes subsequent EPA Administrators from exercising the authority delegated by Congress in §112(n).[25] Under that different regime, according to petitioners, EGUs are subject to §112(d) MACT regulation absent a risk-based §112(c)(9) de-listing, under which one must show that "no source in the category" exceeds an emission level that protects public health *and* the environment.

But Congress included §112(n) specifically because it found the technology-based approach to regulation of non-EGUs was inappropriate for EGUs absent a §112(n) rulemaking

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[24] *Cf. Nat'l Lime Ass'n v. EPA*, 233 F.3d 625, 633 (D.C. Cir. 2000) (challenge not presented in opening brief is waived).

[25] *See* Gov't Ptrs. Br. at 12-13; Env'l Br. at 15-16.

determination. Thus, for example, when Congress addressed the listing of categories of sources of mercury for §112(d) regulation in §112(c)(6) it specifically provided that "[t]his paragraph shall not be construed to require the Administrator to promulgate [MACT] standards for [EGUs]." In short, §112(n)(1)(A) makes little sense if, as petitioners argue, that provision can be cast aside merely by a conclusory "notice" that fails to undertake the analyses or to consider the factors required by §112(n) to make a regulatory determination.

Furthermore, as EPA explains, it has previously revoked "non-final" §112(c) listing actions when it found after rulemaking that stationary sources in the category were not "major," even though it had initially listed the source category as "major." *See* 69 Fed. Reg. 4,689 col. 2. Because a MACT standard is authorized only for a category of "major" stationary sources, once it is established through rulemaking that a source category does not satisfy the statutory predicate for listing, no MACT standard is authorized and the §112(c) listing must be withdrawn without making a §112(c)(9) finding. Similarly, when EPA determined following §112(n) rulemaking that regulating EGUs under §112 was neither "appropriate" nor "necessary," the non-final listing of EGUs under §112(c)(1) had to be withdrawn because the predicate for listing no longer existed.[26]

B. Administrator Browner's December 2000 Notice Was Not Final Action That Deprived Subsequent EPA Administrators of Authority to Act Under §112(n).

Government petitioners agree that §112(n) plays a "threshold role"[27] to "determine the nature of boiler emissions and *whether their control is warranted.*"[28] In a similar vein,

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[26] EPA withdrew its listing for both coal- and oil-fired EGUs. Petitioners have challenged only EPA's §112(n) determination for coal-fired EGUs.

[27] *See* Gov't Ptrs. Br. at 16.

[28] *Id.* at 17 (emphasis added).

environmental petitioners explain that §112(n)(1)(A) "provides a process for deciding *whether to regulate utility units under §112*."[29] According to petitioners, however, this "threshold role" was discharged by Administrator Browner's December 2000 notice of regulatory finding. Even if true, which it is not for the reasons discussed above, Administrator Browner's action did not restrict future EPA Administrators' discretion to make a §112(n) determination through rulemaking.

No one disputes that, when EPA issued its December 2000 notice, it had *not* undertaken a §112(n) rulemaking,[30] had *not* completed the scientific research it had previously identified as being a necessary predicate for a regulatory determination, and had *not* considered all of the factors required for a §112(n)(1)(A) determination (including the impact on EGU mercury emissions of the "imposition of the requirements of this Act" and "alternative control strategies…under this section"). Thus, EPA explained to this Court in April 2001 that the December 2000 §112(n) notice and §112(c) listing of EGUs were not final agency action.[31]

An EPA Administrator can bind future Administrators only by completing a legislative rulemaking, not by issuing a notice shielded from public comment and judicial review. Thus, for example, in *Thomas v. State of New York,* 802 F.2d 1443 (D.C. Cir. 1986), this Court addressed whether a letter sent, in which an outgoing Administrator concluded that acid deposition was endangering public health in the U.S. and Canada, obligated future EPA Administrators to take regulatory action under CAA §115. This Court found that an agency statement which binds subsequent Administrators is a statement of future effect designed to implement law or policy,

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[29] *See* Env'l Br. at 16 (emphasis added).

[30] *See* EPA Br. at 8.

[31] EPA's Motion to Dismiss, at 9 (emphasis added).

and is therefore a "rule." *Id.* at 1446. Because the Administrator had not issued the letter through notice-and-comment rulemaking, this Court found that it was not a "rule" and thus could have no binding effect. *Id.* at 1447.

Similarly, when EPA has taken action that has future regulatory consequences, like "approval" or "disapproval" of a State Implementation Plan (which transforms state-adopted regulations either into federally enforceable ones or refuses to give them federal effect), the courts have uniformly held that EPA must do more than simply publish a notice in the *Federal Register*. Instead, EPA must conduct a "notice and comment" rulemaking in order to create enforceable obligations with future consequences.[32]

For these reasons as well, Petitioners' argument that EPA was required to follow the delisting requirements of §112(c)(9) to remove coal- and oil-fired EGUs from the §112(c) list of major sources has no merit.

C. Unlike Administrator Browner's December 2000 Notice, EPA's March 2005 §112(n)(1)(A) Rule Is the Product of a Formal Rulemaking, and Is Both Lawful and Supported by the Record.

In reviewing past EPA CAA rules, this court has stated that its "analysis is guided by deference traditionally given to agency expertise, particularly when dealing with a statutory scheme as unwieldy and science-driven as the Clean Air Act." *Appalachian Power Co. v. EPA,* 135 F.3d 791, 801-02 (D.C. Cir. 1998); *see also Allied Local & Regional Mfrs. Caucus.v. EPA.,* 215 F. 3d 61, 73 (D.C. Cir. 2000). The Court's role is not to "second-guess the scientific judgments of the EPA." *American Mining Congress v. EPA*, 907 F. 2d 1179, 1187 (D.C. Cir.

[32] *See, e.g., Duquesne Light Co. v. EPA,* 166 F.3d 609, 611 (3rd Cir. 1999)("Each SIP must be submitted to EPA for review and approval. The [CAA] requires a notice and comment period...").

1990); *see also Baltimore Gas & Elec. Co. v. NRDC*, 462 U.S. 87, 103 (1983). Judged against these standards, EPA's §112(n)(1)(A) rule must be affirmed.

Based on an extensive rulemaking record, and after considering voluminous public comments, EPA issued a final §112(n)(1)(A) rule on March 29, 2005 which found that §112 regulation of EGU HAP emissions (including mercury and nickel) was neither "appropriate" nor "necessary." 70 Fed. Reg. 16,002. Petitioners do *not* challenge EPA's decision not to regulate nickel emissions from oil-fired EGUs. That decision did not rely on emission reductions from CAMR or CAIR but rather had a separate and distinct regulatory basis from EPA's decision on mercury emissions. *See supra* p. 11. Petitioners limit their challenge to the claim that, with respect to mercury, EPA's §112(n)(1)(A) rule does not comply with the CAA and lacks record support.

Contrary to Petitioners' claims, EPA's interpretation of the terms "appropriate" and "necessary" is reasonable and consistent with CAA policies and purposes. EPA provides a detailed interpretation of these terms in the preamble to the final §112(n)(1)(A) rule, 70 Fed. Reg. 16,000-02, and in its brief, EPA Br. at 33-40. EPA's interpretation is logical and comports with the language of §112(n)(1)(A); it should be upheld by this Court.

Similarly, the factual record fully supports EPA's §112(n) determination. The rulemaking record contains more than one hundred scientific studies and over 5000 substantive individual comments. EPA's detailed review and consideration of the record material is reflected in the extensive preambles that accompanied the §112(n)(1)(A) rule and EPA's reconsideration of that rule, and in two lengthy responses to comments.[33] In an attempt to cast

[33] *See* 70 Fed. Reg. 15,994-16,033; 71 Fed. Reg. 33,390-95; Response to Comments: Proposed Revision to December 2000 Finding (EPA-HQ-OAR-2002-0056-6193); Response to Comments: Reconsideration (EPA-HQ-OAR-2002-0056-6722).

doubt on this voluminous record, Petitioners have offered a variety of misstatements of fact, unbalanced characterizations of the record, extra-record material,[34] and facts that are not germane to the §112(n)(1)(A) determination. Petitioners' selective presentation does not undermine EPA's §112(n)(1)(A) rule.[35]

For example, Petitioners argue that EPA's reliance on CAIR is arbitrary and capricious because CAIR applies only in 28 states and does not require the regulation of EGUs.[36] Petitioners, however, have grossly discounted the mercury emission reductions from coal-fired EGUs that will result from implementation of CAIR and other CAA programs included in EPA's analysis (such as Title IV) that apply nationally. As EPA's analyses show, hundreds of coal-fired EGUs will install new control equipment, primarily scrubbers and selective catalytic reduction controls ("SCRs"), to meet the SO_2 and NO_x requirements of CAIR and these other programs. Scrubbers and SCRs effectively remove the particulate and gaseous ionic forms of mercury most likely to deposit within several hundred miles of a plant.[37] Petitioners present no compelling reason why EPA's analysis is wrong.

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[34] Environmental petitioners would have this court consider a report on mercury deposition in Steubenville, Ohio and a declaration by an engineering professor, ostensibly submitted as support for their standing demonstration, as a grounds for finding the § 112(n)(1)(A) rule and CAMR inadequate. *See* Env'l Br., App. I. Likewise, Government petitioners offer extra-record material including a Hubbard Brook report that was published mere days before petitioners' brief was filed, and two affidavits offering conclusory and incorrect factual assertions. *See* Govt. Ptr. Br., Affidavit of William O'Sullivan and Declaration of Raymond Vaughan. The material is not part of the administrative record and should not be considered by the Court. *See, e.g., Citizens to Preserve Overton Park, Inc. v. Volpe*, 41 U.S. 402, 420 (1971).

[35] EPA addresses many of petitioners' factual claims in its brief. *See* EPA Brief at 40-81. Respondent-intervenors support those arguments and will not repeat them here.

[36] *See* Govt. Ptr. Br. at 23; Env'l Br at 30.

[37] SCRs convert elemental mercury to the gaseous ionic form which can be removed by scrubbers. For example, plants burning bituminous coal and equipped with a cold-side

State petitioners also claim that CAIR and CAMR do not obviate the need for §112 regulation of EGU mercury emissions because §112(d) MACT standards would require a 90% reduction in mercury emissions while CAMR "requires only a 20% reduction over the next decade."[38] First, there is no evidence in the record that if EPA were to set MACT standards, those standards would require 90% control or, more importantly, would significantly reduce methylmercury levels in fish. In fact, EPA proposed MACT standards in January 2004 that subcategorized EGUs based on the rank of coal burned, with some boilers subject to much lower control levels.[39] EPA also acknowledged that MACT standards must reflect the large variability in mercury emissions that can occur at a given unit as a result of variable mercury concentrations in coal, and the effect of other trace elements on the form of mercury produced during combustion.[40] EPA's proposed MACT would have resulted in a 75% mercury reduction by bituminous-fired EGUs and 15-20% reduction by subbituminous- and lignite-fired units. This is far from the 90% reduction claimed by Petitioners.

Second, Petitioners' comparison of the mercury reductions that would occur under MACT or CAMR are wrong for another reason. The MACT percentage reductions offered by

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electrostatic precipitator and a scrubber have average mercury removal efficiencies of 60%. When an SCR is added, overall mercury removal efficiency increases to 85%. *See* UARG NODA Comments, Attachment 1, Section 5 (EPA-HQ-OAR-2002-0056-5497)(JA4247-53) . EPA has recognized that there are no commercially available, mercury-specific control technologies. *See* 70 Fed. Reg. 28,614.

[38] *See* Govt. Ptr. Br. at 22.

[39] *See* 69 Fed. Reg. 4,665-70. Burning different ranks of coal produces very different mixes of mercury compounds. Particulate and gaseous ionic mercury can be controlled fairly efficiently with existing pollution control equipment. By contrast, EGUs burning subbituminous and lignite coals produce mostly elemental mercury, which is not removed to any appreciable degree by existing control equipment.

[40] *See id.* at 4,670-74.

Petitioners compare mercury in coal to mercury leaving the stack after combustion. By contrast, the mercury reductions Petitioners attribute to CAMR compare 1999 post-stack mercury emissions to post-stack mercury emissions following CAMR implementation. Because, in 1999, 40% of the mercury in the coal was removed by existing control equipment, Petitioners significantly understate the level of emissions reduction required by CAMR, while overestimating those that might be achieved by MACT. In fact, CAMR will require an average 80% mercury control efficiency from *all* coal-fired EGUs, and then cap those emissions at that level for the future.[41] Because of the cap, CAMR is more restrictive than MACT.

Petitioners also argue that, even though §112(n)(1)(A) directs EPA to assess "the hazards to public health reasonably anticipated to occur *as a result of emissions by electric utility steam generating units*" (emphasis added), EPA improperly failed to consider non-EGU mercury emissions. Petitioners' argument is contradicted by the language of §112(n). It is also wrong as a factual matter because EPA included *all* sources of mercury emissions in its modeling analyses.[42]

II. Given EPA's Finding that Mercury Emissions from Existing EGUs Do Not Present Hazards to Public Health, the Court Need Not Reach Petitioners' §111 Arguments.

As noted above, the CAA subjects "any regulation" issued under §112(n) to the §307(d) requirements for notice and comment rulemaking. Section 112(n) tells the Administrator what information he must develop in taking action under that provision. This information includes: (i) "hazards to public health" that are "reasonably anticipated" from EGU HAP emissions; (ii)

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[41] Coal samples collected from all coal-fired EGUs throughout 1999 revealed that 75 tons of mercury enter in the coal annually. CAMR caps emissions at 15 tons per year in Phase 2 thus requiring an 80% average reduction in mercury based on mercury entering all coal-fired EGUs.

[42] *See* EPA, Emissions Inventory and Emissions Processing for the Clean Air Mercury Rule, at 2-5 (EPA-HQ-OAR-2002-0056-6129)(JA1736-39).

the impact of "imposition of the [other] requirements of the Act" on those public health risks; and (iii) "alternative control strategies for emissions which may warrant regulation under this section."

By directing the Administrator in §112(n) "to develop and describe … alternative control strategies" for addressing emissions that "may warrant regulation under [§112]," Congress signaled that control strategies for EGU HAP emissions that may warrant regulation "under this section" could differ from those control strategies that apply to *non*-EGU source categories under §112. In other words, EPA may regulate EGU emissions under §112(n) to the extent "appropriate and necessary," and not where regulation of such emissions under other subsections of §112 (*e.g.*, §112(d)) would impose requirements that either go beyond or do not reach what is "appropriate and necessary" to protect public health. This is confirmed by Congress' direction that EPA take regulatory action establishing legislative rules under *either* §112(d) *or* §112(n) following §307(d) rulemaking procedures. CAA §307(d)(1)(C).

In the notice of proposed rulemaking, EPA interpreted §112(n) as providing independent authority to adopt an alternative control strategy for EGU mercury emissions, to the extent it found some further regulation under §112 was "appropriate and necessary." *See* 70 Fed. Reg. 28,608 col. 1. EPA's reading of the Act makes eminent sense. For example, assume that EGU emissions of a HAP are 50 tons/yr, that the Administrator finds that "hazards to public health" would be eliminated by reducing those emissions to 30 tons/yr, and that imposition of other requirements of the Act would reduce emissions by 15 tons/yr, leaving 35 tons/yr. What then does §112(n) tell the Administrator to do? For this example, the Administrator could determine that the "emissions that warrant regulation under this section" are the 5 tons/yr of emissions that remain after "imposition of other requirements of the Act," because these emissions create the

"hazards to public health" which make regulation under §112 "appropriate and necessary." Once the 5 tons/yr of emissions that "warrant regulation under this section" are eliminated, further regulation of EGU HAP emissions (including §112(d) regulation) would no longer be "warrant[ed] under this section" as "appropriate and necessary" to avoid hazards to public health.

In the instant case, contrary to the above hypothetical, the Administrator concluded that "the [national] level of Hg emissions [35 tons/yr] projected to remain 'after imposition of" sections 110(a)(2)(D) [i.e., the CAIR program] does not cause hazards to public health." 70 Fed. Reg. at 16,004 col. 2. On this basis, the Administrator concluded that regulation of EGU HAP emissions under §112 was not "appropriate." *Id* at 16,005, col. 1.

This finding alone would have been sufficient to end EPA's §112(n) inquiry. Nevertheless, EPA went further and promulgated CAMR under §111. As EPA explains, "CAMR … requires even greater Hg reductions than CAIR," and will ensure that EGU mercury emissions "do[] not result in [future] hazards to public health," by imposing an industry-wide cap on EGU mercury emissions at a level *lower than* the level EPA found would eliminate "reasonably anticipated" hazards to public health from EGU emissions. *Id.* at 16,004 col. 3. Furthermore, EPA found that CAMR "dovetails well with … [regional] emission caps under the [CAIR program]," which also limit EGU mercury emissions, but only the CAMR cap applies nationally. 70 Fed. Reg. 28,606 col. 1. For these reasons, CAMR ensures that public health risks are reduced to levels below those found to be acceptable, and that those emissions cannot increase in the future. *Id.* at 16,005.

As a result, Petitioners challenge to CAMR can produce no benefit for them. If Petitioners prevail on their challenge to EPA's §112(n) determination regarding coal-fired EGUs, the national mercury cap would disappear and this case would have to be remanded to EPA for a

new §112(n) determination. If §112 regulation of EGU mercury emissions were then found to be "appropriate and necessary," a CAMR "cap and trade" program could be promulgated under §112(n). If Petitioners' challenge to EPA's §112(n) determination is rejected, however, the only result of their challenge to CAMR would be to vacate a program that provides additional mercury reductions and a national cap on EGU mercury emissions at a level below the level that EPA concluded, under §112(n), eliminates reasonably anticipated public health risks. 70 Fed. Reg. 16,004, col. 2 and 16,005, col. 1.

III. EPA's CAMR Is Lawful and Supported by the Record.

EPA explained its legal rationale for promulgating CAMR in several *Federal Register* notices.[43] It also developed detailed factual support for determining that a mercury cap-and-trade program is the appropriate §111 "standard of performance" and for the timing and levels of CAMR's annual emission caps.

Petitioners argue that EPA cannot regulate EGU mercury emissions using §111 because §111(d) prohibits the regulation of listed HAPs under that provision.[44] As explained in EPA's brief and in the preamble to the final §112(n)(1)(A) rule,[45] interpreting §111(d) required EPA to address two different and conflicting amendments to §111(d) contained in legislation signed by the President. EPA developed a reasoned way to reconcile the conflicting language and the Court should defer to EPA's interpretation.[46]

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[43] *See* 69 Fed. Reg. 4,696-98; 70 Fed. Reg. 16,029-32.

[44] Petitioners do not challenge EPA's decision to regulate EGU nickel emissions under § 111. *See supra* pp. 14-15.

[45] *See* EPA Br. at 98-118; 70 Fed. Reg. 16,029-32.

[46] *See, e.g., Citizens to Save Spencer County v. EPA*, 600 F.2d 844 (D.C. Cir. 1979).

Petitioners also claim that a cap-and-trade program is unlawful under §111. EPA has offered compelling legal justifications for a mercury cap-and-trade program. *See* EPA Br. at 119-133. A mercury cap-and-trade program is also reasonable as a matter of public policy. Mercury is a global pollutant. About 75% of the mercury that deposits in the U.S. originates from sources outside the U.S. Because a majority of the mercury currently emitted from coal-fired EGUs enters the global pool, only about 8% of the mercury that currently deposits in the U.S. comes from U.S. coal-fired EGUs, and only a small fraction of that enters water bodies and is transformed into methylmercury that ultimately finds its way to humans.

EPA designed CAMR to require near total control of the two forms of mercury that deposit locally and regionally in the U.S.[47] CAMR also imposes a hard cap on mercury emissions that will increasingly restrict mercury emissions from individual units over time as new coal-fired EGUs are built and those units receive mercury allowances.[48] Thus, CAMR maximizes reductions in U.S. mercury deposition while providing EGUs flexibility to achieve those reductions in a cost effective manner.[49]

Petitioners' main factual criticism of CAMR is that it will create mercury "hot spots" and that EPA has failed to consider this issue. Petitioners are wrong on both scores. The issue of mercury "hot spots" was the subject of extensive comments during the rulemaking process.

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[47] *See* Regulatory Impact Analysis, Chapter 8 (EPA-HQ-OAR-2002-0056-6194)(JA2026-44).

[48] Petitioners claim that compliance with CAMR's Phase 2 limits will be delayed by many years. *See* Env'l Br. at 31. CAMR does not allow delayed compliance. CAMR's emissions cap must be met annually assuring that cumulative mercury emissions can never exceed the cap. In fact, CAMR's banking and trading provisions provide incentives for *early* mercury reductions.

[49] One component in setting a §111(a) "standard of performance" is "the cost of achieving such reduction."

Comments ranged from conclusory statements about the existence of "hot spots" that neither offered a definition of the term nor presented factual evidence to support the claim, to comments that included detailed modeling results that showed how mercury deposition would be affected by different regulatory schemes. In responding to these "hot spot" claims, EPA first defined the term[50] and then provided detailed factual reasons why "hot spots" do not currently exist and why they will not result from CAMR implementation. 70 Fed. Reg. 16,025-28. Petitioners' briefs do not offer any reasons for rejecting EPA's definition of a "hot spot." Instead, they persist in making "hot spot" claims without defining that term, which leads them to cite information that sheds no light on the present or future existence of "hot spots."[51]

The rulemaking record contains two detailed modeling analyses of the mercury "hot spot" issue, performed by EPA and the Electric Power Research Institute.[52] These modeling studies looked for areas where mercury deposition from all sources of mercury emissions was above average as well as areas where EGUs contributed disproportionately to mercury deposition. In all cases, CAMR was predicted to reduce mercury deposition, not increase it. This result makes logical sense because a cap-and-trade program encourages control equipment

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[50] EPA defined a "utility hot spot" as "a waterbody that is a source of consumable fish with methylmercury tissue concentrations, attributable solely to utilities, greater than the EPA's methylmercury water criterion of 0.3 mg/kg." 70 Fed. Reg. 16,026 col. 1.

[51] Petitioners rely heavily on a report on mercury deposition measures at one location -- Steubenville, Ohio -- as proof of their "hot spot" claims. *See* Govt. Ptr. Br. at 32-33; Env'l Br. at 33-34. As noted in footnote 34 above, the Steubenville study is not part of the administrative record. In any event, as EPA has explained, the Steubenville mercury deposition measurements were comparable to the deposition levels predicted by EPA's modeling work. Furthermore, the model used by the authors of the Steubenville report can only be used to look back in time. Because it cannot predict the future, the Steubenville work is of no use in answering the question of whether the implementation of CAMR will produce mercury "hot spots."

[52] 70 Fed. Reg. 16,025-28; 71 Fed. Reg. 33,391-92; EPRI Mercury Comments, at 6-11 (EPA-HQ-OAR-2002-0056-2578)(JA928-33); EPRI Reconsideration Comments, at 14-17 (EPA-HQ-OAR-2002-0056-6497)(JA2683-87).

to be installed on plants with the highest emissions so as to minimize the cost per pound of mercury removed. Thus, petitioners' claims that CAMR will create "hot spots" are baseless.

IV. The Special Interests of State Respondent-Intervenors Support the Reasonableness of Both the § 112(n) Rule and CAMR.

In the CAA, Congress assigned States the primary responsibility for the day-to-day regulation of air pollution. State respondent-intervenors have a direct regulatory and economic interest in seeing that EPA's mercury rules are affirmed. In particular, the regulation of air emissions using a cap-and-trade program has proven far more efficient than regulating each facility under a command-and-control approach. A cap-and-trade program is largely self-implementing -- compliance is judged at a single point in time based on whether a facility possesses a sufficient number of allowances to match its actual emissions. By contrast, a command-and-control program requires numerous short-term compliance demonstrations and places a heavy demand on State regulators to verify each source's continuing compliance and to decide whether and how to pursue enforcement actions when occasional exceedances occur.[53]

A cap-and-trade program also benefits State citizens by allowing market forces to govern the choice and timing of emission controls. Under a cap-and-trade program, control equipment is generally installed first at those plants where the cost of control per unit of emissions is the lowest, which are generally the largest and highest emitting facilities. Moreover, in the heavily regulated industry of electricity production, lower compliance costs associated with a cap-and-trade approach will inevitably be passed on to the citizens of each State.

State respondent-intervenors also favor CAMR because it provides States broad discretion in deciding how to allocate mercury allowances among EGUs. This discretion, which

[53] Since both regulatory approaches require continuous emission monitoring, the emissions information available to State regulatory agencies is the same. A cap-and-trade program has the effect of smoothing out the "noise" in instantaneous emission measurements.

is not available under a command-and-control approach, allows State regulators to tailor a State's mercury plan to address such issues as new source set asides to permit construction of new capacity to meet electricity demand growth, the banking of allowances to encourage the retirement of older, less efficient EGUs, and incentives to promote the installation of novel mercury controls.

Finally, State respondent-intervenors have significant doubts about whether mercury "hot spots" will be caused by CAMR's implementation, given the record which shows no significant hot spots and given that larger facilities are controlled first under such a program. Nevertheless, States retain ample legal authority to address any demonstrated instance of mercury hot spots. CAA §116 allows States to adopt state standards that are more stringent than EPA's §111 standards. Using that authority, States can impose under state law additional mercury restrictions on EGUs should future measurements show that such action is necessary.

V. State Respondent-Intervenors North Dakota, South Dakota, Wyoming, and Nebraska Contend EPA's Mercury Allocation Methodology Is Reasonable.

Respondent-intervenor States of North Dakota, South Dakota, Wyoming, and Nebraska support the methodology EPA used to establish state mercury budgets under CAMR.[54] *See* 70 Fed. Reg. 28,622-30. As explained in EPA's brief, *see* EPA Br. at 160-68, EGUs utilizing the various coal ranks have different mercury removal efficiencies because of demonstrated differences in the forms of mercury produced during combustion. Based upon the substantial technical assessment contained in the rulemaking record, EPA's selected coal rank methodology rationally reflects those differences in removal efficiency as measured in pounds of mercury emitted per megawatt of power generated.

[54] The remaining state and industrial respondent-intervenors take no position on EPA's allocation methodology.

CONCLUSION

For the reasons stated above, EPA's § 112(n) rule and CAMR should be affirmed.

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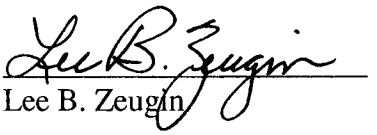
Dated: May 18, 2007
FINAL: July 23, 2007

CERTIFICATE OF COMPLIANCE WITH WORD LIMIT

I hereby certify, pursuant to Federal Rules of Appellate Procedure 32(a)(7)(C) and Circuit Rule 32(a)3(C), that the foregoing final Joint Brief of State Respondent-Intervenors, Industry Respondent-Intervenors, and State Amicus contains 8734 words, as counted by a word processing system that includes headings, footnotes, quotations, and citations in the count, and therefore is within the 8750 word limit established by this Court's Order dated November 29, 2006.



Lee B. Zeugin

STATUTORY AND REGULATORY ADDENDUM

TABLE OF CONTENTS

STATUTORY AND REGULATORY ADDENDUM

CFR

FEDERAL REGISTER

LEGISLATIVE HISTORY

1

Pollutant	Units (7 percent oxygen, dry basis)	Emission limits		
		HMIWI size		
		Small	Medium	Large
Lead	Milligrams per dry standard cubic meter (grains per thousand dry standard cubic feet) or percent reduction.	1.2 (0.52) or 70%	1.2 (0.52) or 70%	1.2 (0.52) or 70%.
Cadmium	Milligrams per dry standard cubic meter (grains per thousand dry standard cubic feet) or percent reduction.	0.16 (0.07) or 65%	0.16 (0.07) or 65%..	
Mercury	Milligrams per dry standard cubic meter (grains per thousand dry standard cubic feet) or percent reduction.	0.55 (0.24) or 85%	0.55 (0.24) or 85%	0.55 (0.24) or 85%.

TABLE 2 TO SUBPART CE—EMISSIONS LIMITS FOR SMALL HMIWI WHICH MEET THE CRITERIA UNDER § 60.33E(B)

Pollutant	Units (7 percent oxygen, dry basis)	HMIWI emission limits
Particulate matter	Milligrams per dry standard cubic meter (grains per dry standard cubic foot).	197 (0.086).
Carbon monoxide	Parts per million by volume	40.
Dioxins/furans	nanograms per dry standard cubic meter total dioxins/furans (grains per billion dry standard cubic feet) or nanograms per dry standard cubic meter TEQ (grains per billion dry standard cubic feet).	800 (350) or 15 (6.6).
Hydrogen chloride	Parts per million by volume	3100.
Sulfur dioxide	Parts per million by volume	55.
Nitrogen oxides	Parts per million by volume	250.
Lead	Milligrams per dry standard cubic meter (grains per thousand dry standard cubic feet).	10 (4.4).
Cadmium	Milligrams per dry standard cubic meter (grains per thousand dry standard cubic feet).	4 (1.7).
Mercury	Milligrams per dry standard cubic meter (grains per thousands dry standard cubic feet).	7.5 (3.3).

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 million Btu per hour).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§ 60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility covered under subpart Da is not covered under this subpart.

[42 FR 37936, July 25, 1977, as amended at 43 FR 9278, Mar. 7, 1978; 44 FR 33612, June 17, 1979]

§ 60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

(a) *Fossil-fuel fired steam generating unit* means a furnace or boiler used in the process of burning fossil fuel for

the purpose of producing steam by heat transfer.

(b) *Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(c) *Coal refuse* means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

(d) *Fossil fuel and wood residue-fired steam generating unit* means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

(e) *Wood residue* means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

(f) *Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

[39 FR 20791, June 14, 1974, as amended at 40 FR 2803, Jan. 16, 1975; 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978; 48 FR 3736, Jan. 27, 1983; 65 FR 61752, Oct. 17, 2000]

§ 60.42 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35 percent opacity, except that a maximum or 42 percent opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32 percent opacity, except that a maximum of 39 percent opacity shall be permitted for not more than six minutes in any hour.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 42 FR 61537, Dec. 5, 1977; 44 FR 76787, Dec. 28, 1979; 45 FR 36077, May 29, 1980; 45 FR 47146, July 14, 1980; 46 FR 57498, Nov. 24, 1981; 61 FR 49976, Sept. 24, 1996; 65 FR 61752, Oct. 17, 2000]

§ 60.43 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:

(1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO2}=[y(340)+z(520)]/(y+z)$$

where:

PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) [Reserved]

(e) Units 1 and 2 (as defined in appendix G) at the Newton Power Station

owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 nanograms per joule (1.1 lb per million Btu) combined heat input to Units 1 and 2.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 52 FR 28954, Aug. 4, 1987]

§ 60.44 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.

(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

(3) 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 nanograms per joule heat input (0.60 lb per million Btu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c) and (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260) + x(86) + y(130) + z(300)}{w + x + y + z}$$

where:

PS_{NOx}=is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w= is the percentage of total heat input derived from lignite;

x= is the percentage of total heat input derived from gaseous fossil fuel;

y= is the percentage of total heat input derived from liquid fossil fuel; and

z= is the percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for nitrogen oxides does not apply.

(d) Cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978; 51 FR 42797, Nov. 25, 1986]

§ 60.45 Emission and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis.

(3) Notwithstanding §60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under §60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in §60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests under §60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

(c) For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in §60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	(1)	500
Liquid	1,000	500
Solid	1,500	1000
Combinations	1,000y+1,500z	500(x+y)+1,000z

[1] Not applicable.

where:

x=the fraction of total heat input derived from gaseous fossil fuel, and

y=the fraction of total heat input derived from liquid fossil fuel, and

z=the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (c)(3) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E=CF[20.9/(20.9-\text{percent } O_2)]$$

where:

E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E=CF_c\ [100/\text{percent } CO_2]$$

where:

E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e) (1) and (2) of this section are derived as follows:

(1) *E*=pollutant emissions, ng/J (lb/million Btu).

(2) *C*=pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where *M*=pollutant molecular weight, g/g-mole (lb/lb-mole). *M*=64.07 for sulfur dioxide and 46.01 for nitrogen oxides.

(3) $\%O_2$, $\%CO_2$=oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388–77, 90, 91, 95, or 98a (incorporated by reference—see § 60.17), $F=2{,}723\times10^{-17}$ dscm/J (10,140 dscf/million Btu and $F_c=0.532\times10^{-17}$ scm CO_2/J (1,980 scf CO_2/million Btu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388–77, 90, 91, 95, or 98a (incorporated by reference—see § 60.17), $F=2.637\times10^{-7}$ dscm/J (9,820 dscf/million Btu) and $F_c=0.486\times10^{-7}$ scm CO_2/J (1,810 scf CO_2/million Btu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F=2.476\times10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c=0.384\times10^{-7}$ scm CO_2/J (1,430 scf CO_2/million Btu).

(iv) For gaseous fossil fuels, $F=2.347\times10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c=0.279\times10^{-7}$ scm CO_2/J (1,040 scf CO_2/million Btu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/million Btu) for butane.

(v) For bark $F=2.589\times10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c=0.500\times10^{-7}$ scm CO_2/J (1,840 scf CO_2/million Btu). For wood residue other than bark $F=2.492\times10^{-7}$ dscm/J (9,280 dscf/million Btu) and $F_c=0.494\times10^{-7}$ scm CO_2/J (1,860 scf CO_2/ million Btu).

(vi) For lignite coal as classified according to ASTM D388–77, 90, 91, 95, or 98a (incorporated by reference—see § 60.17), $F=2.659\times10^{-7}$ dscm/J (9,900 dscf/million Btu) and $F_c=0.516\times10^{-7}$ scm CO_2/J (1,920 scf CO_2/million Btu).

(5) The owner or operator may use the following equation to determine an *F* factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate *F* on a wet basis, consult the Administrator) or F_c factor (scm CO_2/J, or scf CO_2/million Btu) on either basis in lieu of the *F* or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\frac{[227.2\,(\text{pct. H}) + 95.5\,(\text{pct. C}) + 35.6\,(\text{pct. S}) + 8.7\,(\text{pct. N}) - 28.7\,(\text{pct. O})]}{\text{GCV}}$$

$$F_c = \frac{2.0\times10^{-5}\,(\text{pct. C})}{\text{GCV(SI units)}}$$

$$F = \frac{10^{6}[3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)]}{GCV\,(\text{English units})}$$

$$F_c = \frac{20.0(\%C)}{GCV\,(\text{SI units})}$$

$$F_c = \frac{321\times10^{3}(\%C)}{GCV(\text{English units})}$$

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178–73 (Reapproved 1979), 89, or D3176–74 or 89 (solid fuels) or computed from results using ASTM D1137–53 or 75, D1945–64, 76, 91, or 96 or D1946–77 or 90 (Reapproved 1994) (gaseous fuels) as applicable. (These five methods are incorporated by reference—see § 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015–77 for solid fuels and D1826–77 for gaseous fuels as applicable. (These two methods are incorporated by reference—see § 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \text{ or } F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

where:

X_i=the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)

F_i or $(F_c)_i$=the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n=the number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in § 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity.* Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of § 60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of § 60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average

per hour of up to 39 percent opacity need not be reported.

(2) *Sulfur dioxide.* Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under § 60.43.

(3) *Nitrogen oxides.* Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under § 60.44.

[40 FR 46256, Oct. 6, 1975]

EDITORIAL NOTES: 1. FOR FEDERAL REGISTER citations affecting § 60.45, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

2. At 65 FR 61752, Oct. 17, 2000, § 60.45(f)(5)(ii) was amended by revising the words "ASTM D1826–77" to read "ASTM D1826–77 or 94." and by revising the words "ASTM D2015–77" to read "ASTM D2015–77 (Reapproved 1978), 96, or D5865–98." However, this amendment could not be incorporated because these words do not exist in paragraph (f)(5)(ii).

§ 60.46 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_x standards in §§ 60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of particulate matter, SO_2, or NO_x shall be computed for each run using the following equation:

$$E = C\ F_d\ (20.9)/(20.9 - \%\ O_2)$$

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

$\%O_2$ = oxygen concentration, percent dry basis.

F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160 ±14 °C (320 ±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

(3) Method 9 and the procedures in § 60.11 shall be used to determine opacity.

(4) Method 6 shall be used to determine the SO_2 concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be taken simultaneously with, and at the same point as,

the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 shall be used to determine the NO_X concentration.

(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_X sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_X sample.

(iii) The NO_X emission rate shall be computed for each pair of NO_X and O_2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§ 60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D2015–77 (Reapproved 1978), 96, or D5865–98 (solid fuels), D240–76 or 92 (liquid fuels), or D1826–77 or 94 (gaseous fuels) (incorporated by reference—see § 60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate (E) of particulate matter, SO_2 and NO_X may be determined by using the F_c factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = C\ F_c\ (100/\%CO_2)$$

where:

E=emission rate of pollutant, ng/J (lb/million Btu).

C=concentration of pollutant, ng/dscm (lb/dscf).

$\%CO_2$=carbon dioxide concentration, percent dry basis.

F_c=factor as determined in appropriate sections of Method 19.

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in paragraph (b) (2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ±3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa}=0.209\ (F_{da}/F_{ca})$, then the following procedure shall be followed:

(A) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than 0.97 F_{oa} and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than 1.03 F_{oa} and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, e.g., if F_o is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used with Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is used in place of the condenser (section 2.1.7) of Method 5.

(ii) All applicable procedures in Method 8 for the determination of SO_2 (including moisture) are used:

(4) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO_2 emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration ($\%O_2$) for the emission rate correction factor.

(6) For Method 3, Method 3A or 3B may be used.

(7) For Method 3B, Method 3A may be used.

[54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989, as amended at 55 FR 5212, Feb. 14, 1990; 65 FR 61752, Oct. 17, 2000]

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

SOURCE: 44 FR 33613, June 11, 1979, unless otherwise noted.

§ 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

(b) Heat recovery steam generators that are associated with stationary combustion turbines burning fuels other than 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. Heat recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average are subject to this part and are not subject to subpart KKKK of this part. This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the combined cycle gas turbine burn fuels other than synthetic-coal gas, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that

2

federal register

TUESDAY, OCTOBER 14, 1975

PART V:

ENVIRONMENTAL PROTECTION AGENCY

■

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Asbestos and Mercury

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 431–2]

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

Amendments to Standards for Asbestos and Mercury

On October 25, 1974 (39 FR 38064), pursuant to section 112 of the Clean Air Act, as amended, the Administrator proposed amendments to national emission standards for the hazardous air pollutants asbestos and mercury. The Administrator also proposed amendments to Appendix B, Test Methods, of this part.

Interested persons representing industry, trade associations, environmental groups, and Federal, State and local governments participated in the rulemaking by sending comments to the Agency. Commentators submitted 40 letters, many with multiple comments. The comments have been considered, and the proposed amendments have been reevaluated. Each comment, some of which were submitted by more than one party, has been separately addressed in writing by the Agency. The Freedom of Information Center, Room 202 West Tower, 401 M Street, SW, Washington, D.C. has copies of the comment letters received and a summary of the issues and Agency responses available for public inspection. In addition, copies of the issue summary and Agency responses may be obtained upon written request from the EPA Public Information Center (PM–215), 401 M Street, S.W., Washington, D.C. 20460 (specify Public Comment Summary—Proposed Amendments to National Emission Standards for Hazardous Air Pollutants—Asbestos and Mercury). Where determined by the Administrator to be appropriate, changes have been made to the proposed amendments, and the revised version of the amendments to the national emission standards for asbestos and mercury is promulgated herein. The principal changes to the proposed amendments and the Agency's responses to the major comments received are summarized below.

Copies of *Background Information on National Emission Standards for Hazardous Air Pollutants—Proposed Amendments to Standards for Asbestos and Mercury* (EPA–450/2–74–009a) which explains the basis for the proposed amendments are available on request from the Emission Standards and Engineering Division, Research Triangle Park, North Carolina 27711, Attention: Mr. Don R. Goodwin.

Asbestos

CHANGES TO PROPOSED AMENDMENTS

Manufacturing. The Agency received numerous comments stating that the proposed amendments should apply only to asphalt concrete manufacturing plants that use asbestos. This was the Agency's intent. Section 61.22(c) has been revised by the addition of the wording, "that use commercial asbestos."

Demolition and Renovation. A comment was received during review of the amendments within the Agency that ducts can be insulated with amounts of friable asbestos material similar to those on boilers, tanks, reactors, turbines, furnaces and structural members, and should be covered by the demolition and renovation regulations. Since demolition and renovation operations can involve ducts insulated with appreciable quantities of friable asbestos material, "ducts" has been added to the list of apparatus that are covered by the amendments.

The comment was made that the quantity of friable asbestos material proposed as the minimum amount for establishing renovation operations as major sources of asbestos subject to the proposed amendments was arbitrary, but should also apply to demolition operations. The Agency explained in the preamble to the proposed amendments that this amount of asbestos is typically contained in a four-unit apartment building, which is the maximum size for apartment buildings excluded from the demolition provisions. Therefore, the minimum quantity of friable asbestos material covered by the demolition and renovation provisions is essentially equivalent. The Agency considered applying regulations only to demolition operations in which more than a specified amount of friable asbestos material was involved, prior to promulgation of demolition provisions on April 6, 1973 (38 FR 8820). This approach was rejected primarily because it would complicate enforcement procedures. However, the Agency realizes that certain commercial buildings contain smaller amounts of friable asbestos material than the lower size cutoff limit proposed for renovating operations. On reevaluation, the Agency concluded that the available information justifies changing the proposed amendment to allow exemption of demolition operations involving less than 80 meters of friable asbestos pipe insulation and less than 15 square meters of friable asbestos material used to insulate or fireproof any duct, boiler, tank, reactor, turbine, furnace or structural member. The owner or operator of a demolition operation desiring this exemption must notify the Administrator, at least 20 days prior to beginning demolition, of the measured or estimated amount of friable asbestos material involved in the demolition. This will permit the exception to be implemented without requiring prior inspection of every site by Agency personnel, which would be an excessive enforcement burden. This differs from the reporting requirements of the renovation provisions of the amendments. The nature of renovation operations necessitates a greater familiarity on the part of the operator with the quantities of friable asbestos materials present than for demolition operations. For this reason, the Agency believes that it is not necessary to require reports from all renovation operations in order to ensure effective enforcement of the renovation provisions that apply to only larger renovation operations.

Several comments were received which stated that operating machinery could be damaged by wetting procedures during certain renovation operations. The wetting during renovation of a heated boiler, near sensitive electric equipment, and over operating machinery in an industrial plant were mentioned as specific examples. One comment also stated that portable local exhaust ventilation systems are effective alternatives to wetting. The proposed amendments have been changed to allow the use of local exhaust ventilation systems when damage to equipment from wetting is unavoidable, provided that the system captures the asbestos particulate material produced during the removal of friable asbestos material and discharges no visible emissions from its exhaust. The Administrator will make determinations, upon request, of whether damage to equipment from wetting would be unavoidable.

Several comments were received which stated that the proposed frequency for submitting to the Agency written notices of intention to perform repetitive renovation work at a single facility was excessive. One commentator suggested that definitions for "emergency renovation" and "routine maintenance renovation" be included, and that a yearly filing of intention to renovate should be allowed for each industrial plant. It is evident from the comments received that some plants perform renovation operations very frequently, such as twice a week. The proposed reporting requirements for such plants would be excessive. The proposed amendment has been changed so that these requirements are reduced, and the applicability of the requirement is more clearly defined by adding more detailed language and definitions for "planned renovation" and "emergency renovation" operations. Additionally, the applicability of the amendment has been clarified by specifying how the quantities of asbestos involved in "planned renovation" and "emergency renovation" are to be determined. The basic characteristic that distinguishes the two types of renovation operations is the degree of predictability of their occurrence. The amount of friable asbestos material that will be removed or stripped within a given period of time can be predicted for planned renovation operations, including both scheduled and non-scheduled operations, whereas no such prediction can be made for emergency renovation operations. The given period of time for predicting purposes has been specified to be between 30 days and one year for planned renovation operations involving individually non-scheduled operations. A reporting time shorter than 30 days would require the submission and review of a large number of reports, and predictions over periods longer than one year could give inaccurate predictions of friable asbestos material to be removed. In emergency renovation operations, the amount of friable asbestos material that is subject to the amendment is the total amount of such mate-

rial that will be removed or stripped as a result of the individual emergency.

One commentator stated that the proposed amendment covering renovation could be circumvented by the carrying out of small portions, which are individually not subject to the amendment, of a larger operation. Section 61.17 has been added to the General Provisions to explicitly prevent this potential circumvention and to apply in general to circumvention of all standards promulgated under this part.

One commentator stated that a requirement in § 61.22(d)(2)(vi) of the proposed amendments was inconsistent and should be revised. This section required that friable asbestos material removed from buildings greater than 50 feet in height be transported to the ground via dust-tight chutes or containers. The cited inconsistency arises because this requirement applied at all heights, including those less than 50 feet, for a building 50 feet or gretaer in height, whereas it did not apply to buildings less than 50 feet in height. The requirement has been changed so that it applies only to materials that have been removed or stripped at more than 50 feet above ground level.

Several minor changes have been made in response to comments. Language has been added to allow delivery of notices of intention to renovate or demolish to the Administrator by means other than the U.S. mail. There is a minor clarifying language change between § 61.22(d)(2)(i) of the proposed demolition provisions and the corresponding provision, § 61.22(d)(4)(i), of the regulations promulgated herein. A comment suggested the term "adequately wetted" should be defined and differentiated from "thoroughly wetted," since both terms appeared in the proposed amendments. The use of these terms has been reevaluated, and a definition of "adequately wetted" has been added. The term "thoroughly wetted" has been deleted and the term "adequately wetted" has been used throughout.

The Agency has made a revision in the proposed requirement [§ 61.22(d)(1)] for notification of intention to perform renovation or demolition operations. An additional reporting requirement for the name and location of the waste disposal site where demolition and renovation waste will be deposited has been added to assist in enforcing the waste disposal provisions of the amendments.

Spraying. During review of the amendments within the Agency, a question arose concerning whether the waste generated by operations that use spray-on materials which contain less than one percent of asbestos by weight to insulate or fireproof buildings, structures, pipes and conduits was covered by the asbestos waste disposal amendment [§ 61.22(j)]. The spraying provisions do not apply to such operations, though reports of the operations were required by the standard promulgated on April 6, 1973. Therefore, the waste disposal processes associated with these operations are not regulated by the waste disposal amendments. Based on Agency enforcement experience since promulgation of the standard on April 6, 1973, the required reporting of spraying operations where less than 1 percent asbestos material is used is felt to be unnecessary. Accordingly, the Agency has revised the reporting requirements of paragraph 61.22(e) to apply only to spray-on insulation and fireproofing material that contains more than one percent asbestos by weight.

Waste Disposal. The proposed amendments would have applied directly to all waste disposal sites that accept asbestos waste from any emission source covered under the asbestos standard. The Agency estimated that approximately 2500 disposal sites would be covered. Review of these proposed amendments within the Agency indicated that enforcement would have required a disproportionate commitment of Agency resources. Alternative means of controlling asbestos emissions from waste disposal sites were therefore examined.

The number of acceptable waste disposal sites that meet the criteria in § 61.22(j)(3) of the proposed amendments, which are similar to the criteria for sanitary landfills, has increased significantly within the past several years and the trend is continuing in that direction. This trend is noted in a recent publication ("Waste Age," January 1975). This indicates that acceptable sites (i.e., private and municipal sanitary landfills) which follow practices that reduce asbestos emissions will be available for disposal of asbestos-containing waste. Therefore, it was determined that an effective means of reducing emissions from waste disposal sites without undue enforcement burdens would be to require already-regulated asbestos waste generators to dispose of asbestos-containing wastes at properly operated disposal sites. This is provided for in the amendments herein promulgated.

The Agency's greatest concern is with disposal sites which accept large quantities of asbestos waste. In most cases, companies which generate large quantities of asbestos-containing waste also own and operate their own disposal sites because of convenience and economics. For example, all domestic asbestos mills operate their own tailings disposal sites. The Agency anticipates that these large waste generators will operate their disposal sites in the future in compliance with the proposed §61.22(l) in order to meet the requirement that they dispose of their waste at a acceptable sites.

Inactive disposal sites may also be major emission sources if they contain large amounts of asbestos waste. It is likely that at inactive sites containing small amounts of asbestos waste the asbestos is covered by non-asbestos waste, and the chance of significant asbestos emissions is small. It was decided to require that those inactive sites which are known to contain large quantities of asbestos comply with the standards specified in section 61.22(l) to reduce asbestos emissions. This category of asbestos waste disposal sites is usually operated by the sources that generate the asbestos-containing wastes, as noted above. Accordingly, the amendments promulgated herein apply to inactive disposal sites that have previously been operated by certain sources covered by the asbestos standard. The owner of such an inactivated site must comply with the amendments regardless of whether or not he generated the waste or operated the disposal site when it was active. This category of sites includes asbestos mill tailings disposal sites, and the large disposal sites at asbestos manufacturing and fabricating plants which have caused concern in the past. The owners or operators of spraying, demolition and renovation operations have not operated disposal sites in the past and are not expected to do so in the future. Due to the nature of such operations, the wastes generated are deposited at waste disposal sites which accept mostly non-asbestos-containing waste. As a result, the asbestos waste is effectively covered, thereby preventing emissions even in open dumps. For these reasons, inactive waste disposal sites that have been used by spraying, renovation and demolition are not regulated.

The amendments promulgated herein will control inactive asbestos waste disposal sites that contain large quantities of asbestos waste. The Agency's enforcement resources will be more effectively utilized since approximately 2000 waste disposal sites will not be directly regulated by the promulgated amendments. This should facilitate enforcement and protection of the public health.

The comment was made that the proposed permanent posting of warning signs at inactive asbestos waste disposal sites would be overly restrictive. The warning signs were intended primarily to warn the general public of the potential hazards that could result from creating dust by such disturbances as walking on exposed asbestos waste. If the disposal site is properly covered over as required by the alternative methods of complying with the proposed amendment for waste disposal sites, such minor disturbances will not generate asbestos emissions. Accordingly, the proposed amendment has been changed, and warning signs are not required if an inactive disposal site applies and properly maintains a covering of compacted non-asbestos-containing material at least 60 centimeters (ca. 2 feet) in depth, or at least 15 centimeters (ca. 6 inches) in depth with a cover of vegetation. The proposed amendment would have also required that active asbestos waste disposal sites post warning signs. The amendments promulgated herein do not apply directly to active disposal sites, and the specified operating practices for acceptable disposal sites do not require the posting of warning signs provided an appropriate cover of at least 15 centimeters (ca. 6 inches) of non-asbestos-containing material is applied to the active portion of the site at the end of each operating day. Comments were received that suggested the Agency should allow the use of existing natural barriers as substitutes for fences that are intended to deter access to some types of asbestos waste disposal sites. The Agen-

cy agrees that certain natural barriers, such as deep ravines and steep cliffs, can be as effective as fences in deterring access. The proposed amendment has been changed to suspend the requirements for fences, and also warning signs, when a natural barrier provides an adequate deterrent to public access. Upon request and supply of appropriate information, the Administrator will determine whether a specific type of fence or a natural barrier adequately deters access to the general public. In response to another comment, the proposed amendment for fencing of asbestos waste disposal sites has been revised to allow fences to be placed either along the property line of an affected source that contains a waste disposal site or along the perimeter of the disposal site itself. Either type of fence provides the necessary deterrent to public access to the disposal site.

Several comments were received on the proposed prohibition of incineration of containers that previously contained commercial asbestos. One commentator stated that the prohibition seemed undesirable because asbestos is thermally degraded at a temperature of 600° C. The Agency considered: (a) the uncertainty that the feed material to an incinerator will be uniformly heated to the combustion chamber temperature, (b) the uncertainty concerning the decomposition temperature of asbestos, and (c) the results of a stack gas test that detected emissions of asbestos from a sintering process in which the temperature attained was well above 600° C, in evaluating the comment. The Agency concluded that the available data do not justify changing the proposed regulation on grounds that the asbestos is thermally degraded in the combustion process. Another comment suggested that incineration should be permitted, provided there are no visible emissions of asbestos particulate matter from the incinerator. Information presented to the Agency after proposal indicated that some small incinerators, such as those operated by asbestos manufacturing plants, can be operated with no visible emissions. The proposed prohibition on incineration of containers that previously held commercial asbestos has been deleted. The provisions of the amendments for the disposal of asbestos-containing waste materials apply in particular to the disposal of containers that previously held commercial asbestos. Therefore, these containers can be incinerated under the amendments, provided the incineration operation does not discharge visible emissions.

Two commentators suggested that the proposed amendments should not require that EPA warning labels be attached to containers of asbestos waste in addition to the warning labels specified in regulations issued by the U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). The Agency agrees that both labels adequately convey the desired information; therefore, the proposed amendment has been changed to allow the OSHA warning label to be used in place of the EPA warning label.

Several commentators requested that the proposed alternative method of compliance included in the asbestos waste disposal amendments, which specified that the waste be formed into non-friable pellets, be changed to accommodate shapes other than pellets. The precise size and shape of the processed, non-friable waste is not important, and the amendment has been reworded to explicitly permit the forming of asbestos wastes into pellets or any other shapes.

A comment was made during review within the Agency that asbestos-containing wastes subject to the proposed amendment are sometimes used to surface roadways and that this practice should be prohibited. The Agency agrees that the use of asbestos-containing wastes on roadways can cause asbestos emissions similar to those caused by the use of asbestos tailings on roadways, which is prohibited by the asbestos standard. Vehicular traffic on roadways can pulverize asbestos waste and liberate fibers that can become airborne in the wake of moving vehicles and by the wind. The use of asbestos-containing wastes has therefore been prohibited from use on roadways.

The proposed amendment for waste disposal at asbestos mills included a provision requiring no visible emissions to the outside air from the deposition of asbestos ore tailings onto a disposal pile. An alternative method of compliance required that the waste be adequately wetted with a dust suppressant agent prior to deposition. Two commentators stated that an exemption from the wetting requirement of the alternative method is needed when the temperature at the disposal site is below freezing, to prevent freezing of the tailings and permit continued operation of the asbestos mill at such low temperatures. The investigation carried out by the Agency prior to proposal of the amendment indicated that wetting of asbestos tailings is the only presently available method for effectively controlling particulate emissions from the deposition operation. In response to the comments received, the Agency further investigated the cold weather operational problems of disposal systems for wetted asbestos tailings. Discussions were held with operators of three Canadian asbestos mills that frequently operate under cold weather conditions and have installed tailings wetting systems, with a firm that is experienced in designing systems to suppress dust generated by materials conveying operations, and with several non-asbestos mineral mining facilities that operate wetting systems for crushing and conveying operations. The investigation revealed that several Canadian asbestos mills are presently experimenting with wet tailings disposal systems to extend operation to temperatures substantially below freezing. However, the Agency is aware of no such system that has operated in a continuous manner at temperatures below —9.5°C (15°F). Accordingly, the Agency has concluded that wet tailings disposal systems for asbestos mills are not available for disposal site temperatures below —9.5°C (15°F), and the proposed amendment has been changed to provide an exemption for wetting of tailings below this temperature. Only one existing domestic asbestos mill is expected to use the exemption to a significant extent. An examination of hourly temperatures representative of the location of that plan, and extending over a period of one year, showed that hourly temperatures are below 15°F for approximately 7 percent of the time.

Asbestos emissions at asbestos mill tailings disposal piles are contributed by the tailing conveying operation, the deposition operation, and wind entrainment of asbestos-containing particulate from the surface of the disposal pile. The first emission source is subject to previously promulgated regulations (38 FR 8820), and the latter two sources are subject to the amendments promulgated herein. The major sources of asbestos emissions from process gas streams at asbestos mills, namely effluents from crushers, dryers and milling equipment, are also covered by the previously promulgated regulations (38 FR 8820). The amendments promulgated herein, including an exemption from wetting of asbestos tailings at temperatures below —9.5° C (15° F), together with the standards promulgated on April 6, 1973 (38 FR 8820), represent use of the best available technology for control of emissions from asbestos mills. This is consistent with the determination of the Administrator that best available technology should be used to control major sources of asbestos emissions to protect the public health with an ample margin of safety.

The reporting format of Appendix A has been changed by the addition of paragraphs "C" and "D", to accommodate the addition of disposal of asbestos-containing wastes and certain inactive asbestos waste disposal sites to the amendments. The additional information required is essential for determining compliance with the regulations. Appendix A has also been revised into a new computer format which will promote more effective enforcement of the regulations. Section 61.24 has been revised to reflect the additional reporting information requested in Appendix A.

ADDITIONAL COMMENTS

Manufacturing and Fabrication. One comment questioned the need for including asphalt concrete manufacturing plants in the proposed amendments. The rationale for including asphalt concrete plants as major sources of asbestos is discussed in the background information document for the proposed amendments (EPA–450/2–74–009a). Two commentators suggested that the manufacture of asphalt concrete containing less than 3 to 5 percent asbestos in the total mixture should be exempt from the regulations. However, asbestos asphalt concrete typically contains 1 to 2 percent asbestos, and the Agency determined that asbestos asphalt concrete operations using even these low percentages of asbestos are major sources. No data or information were received that would indicate asphalt concrete plants are not

major sources, and the regulations promulgated herein apply to such sources. The Agency received two comments that the individual emission sources within an asbestos asphalt concrete plant which are subject to the proposed amendments should be specified. The Agency feels that revisions are not necessary. Only component operations that may emit asbestos are covered by the provisions; for example, if no asbestos is added to the aggregate dryer, the emissions from the dryer alone are not covered.

The possibility that the enforcement of the amendments promulgated herein for asphalt concrete plants may be in conflict with the enforcement of new source performance standards for asphalt concrete plants was raised by one commentator. It is possible that both the new source performance standard and the national emission standard for asbestos will apply simultaneously to emissions from some operations at some new and modified plants. Where this occurs, the visible emission standard promulgated herein applies to asbestos particulate matter, even though it is more restrictive than the opacity regulation of the new source performance standard. A more stringent standard is justified when asbestos is being processed because of the hazardous nature of asbestos.

Comments were received that the proposed definition of "fabricating" needed to be clarified. The Agency reviewed the definition and determined that changes in the definition are not necessary. Fabricating includes any type of processing, excluding field fabrication, performed on manufactured products that contain commercial asbestos. The Agency acknowledges that some component processes of asbestos fabricating operations could generate visible emissions in such a manner that the visible emissions do not contain asbestos generated by the process, though the commentators did not cite any specific examples. The Agency has observed this type of process in asbestos manufacturing operations. For example, visible emissions of organic materials are sometimes generated during the curing of asbestos friction products in operations where asbestos is bound into a matrix of non-asbestos material but the asbestos is not transferred into the emission stream. Such operations are in compliance with the standard of no visible emissions containing particulate asbestos material.

One commentator stated that some field fabrication operations release significant amounts of asbestos. The Agency's investigation prior to proposal of the amendments showed that there is only limited field fabrication of asbestos products other than insulating products. The fabrication of friable asbestos insulation was determined to be the only major asbestos field fabrication source, and this is regulated by prohibiting the use of such materials after the effective date of the amendments promulgated herein. In the judgment of the Administrator, the comment did not contain sufficient information to justify including other categories of asbestos field fabrication in the amendments. One commentator recommended that the Agency impose a standard of 0.03 grain per cubic foot for asbestos emissions in addition to the no-visible-emission standard. It is the judgment of the Agency that there are no sufficiently reliable emision measurement techniques to provide a basis for such a numerical standard and the setting of numerical standards should be delayed until accurate asbestos measuring techniques are available.

Demolition and Renovation. Comments were received which suggested that the proposed renovation provisions should not apply to operations carried out within buildings, or to operations regulated by the Occupational Safety and Health Administartion (OSHA) for worker exposure to asbestos. The Agency recognizes that there may be less asbestos emissions from stripping of friable asbestos materials within a structure than from stripping in an unenclosed area. However, asbestos from the stripping operation carried out within a building or structure can be discharged into the outside air from building ventilation systems, windows and doors. Further, the disposal of friable asbestos waste materials generated by renovation operations, which includes the transport of waste materials to a disposal site, is an emission source that needs to be controlled regardless of whether the renovation is performed in the outside air or in buildings. In the judgment of the Administrator, the control of such asbestos emissions is necessary and is part of the best available control technology. The OSHA regulations (29 CFR 1910.93a) require that, ". . . insofar as practicable . . .," asbestos material be removed while wetted effectively to prevent emission of asbestos in excess of the specified OSHA exposure limit, but also specifically require that employees shall be provided with respiratory equipment for all spraying, demolition and removal of asbestos materials. The purpose of the OSHA standard, to protect employees' health, can be achieved by the use of respiratory equipment, even in those situations where wetting is not implemented and emissions may produce concentrations in excess of the OSHA exposure limit. The extent to which the resulting concentrations in the outside air are protective of public health is unknown. Accordingly, the proposed renovating provisions do not exempt operations that are controlled by OSHA regulations.

Two commentators stated that the alternative to the wetting requirement in the demolition provisions at sub-freezing temperatures should be allowed at all temperatures. In contrast, another commentator suggested that suspension of the wetting requirements at sub-freezing temperatures should be subject to a permit procedure that would discourage demolition at sub-freezing temperatures. The alternative was proposed because, in the judgment of the Agency, worker safety would be unduly jeopardized by the unsafe footing caused by ice formation from water use under freezing conditions. The proposed alternative is less restrictive on demolition contractors than a second course of action that was considered, namely the prohibition of demolition under freezing conditions. The proposed alternative suspends only a portion of the wetting requirements under freezing conditions. Pipes, ducts, boilers, tanks, reactors, turbines, furnaces and structural members insulated or fireproofed with friable asbestos materials must be removed from the building in sections, to the maximum extent practicable, before wrecking of the building. The stripping of asbestos materials from the previously removed sections must be accompanied by wetting at all temperatures, and the resulting asbestos waste materials must be wetted at all temperatures. These procedures do not jeopardize worker safety. Therefore, the promulgated demolition provisions are based on the use of the best available emission control methods at all temperatures, and these methods are different for non-freezing and freezing conditions.

Another comment indicated that sprayed fireproofing was the only type of asbestos material that could cause asbestos emissions to the atmosphere during demolition operations, and that molded insulation is not readily released into the air. The Agency has inspected both types of materials and has found that some types of molded insulation and plaster that contain asbestos are friable. Therefore, buildings containing these materials are covered by the amendments promulgated herein.

Comments were received that the Agency has a responsibility to develop asbestos measurement methods and determine by use of measurement methods whether demolition is a major source of asbestos emissions. The Agency keeps abreast of newly developed measurement techniques in the asbestos industry, and the development of asbestos measurement techniques is currently being funded by the Agency. No new information on measurement techniques was received in the comments. The Agency previously made the determination that building demolition is a major source of asbestos emissions, and no new information has been submitted to demonstrate that it is not a major source. Demolition and renovation operations generate short-term exposures of urban populations to asbestos. Since promulgation of the demolition regulations on April 6, 1973, new biological evidence supporting the significance of single short-term exposures of asbestos has been obtained. One-day inhalation exposures in animal experiments have produced an increase in the incidence of mesotheliomas. (Wagner, J. C., Berry, G., and Timbrell, V., "The Effects of the Inhalation of Asbestos in Rats", *Br. J. Cancer 29*, pp. 252–269, 1974). A copy of this article is available for inspection at the Public Information Reference Center, Room 2404, Waterside Mall, 401 M Street, SW, Washington, D.C. 20460. It can be concluded that human asbestos exposure for periods typically required to perform demolition and renovation operations is hazardous. Therefore, the Agency has not changed its prior determination that building demolition is a major source of asbestos emissions. Another commentator was concerned that

the demolition sources now covered by the asbestos standard as major sources were not defined as major sources by the National Academy of Sciences (NAS) study, which was cited by the Agency as a basis for the demolition regulation. The NAS study did not define categories of asbestos materials other than sprayed fireproofing as major emission sources because data were available at that time on fireproofing only. The Agency had concluded prior to proposing asbestos standards on December 7, 1971 that any friable asbestos material used for insulation or fireproofing has a comparable potential to create asbestos emissions upon demolition or renovation as sprayed fireproofing, and therefore these materials are also covered by the regulations.

Several comments were received stating that the definitions of "friable asbestos material," "asbestos," and "asbestos material" are vague and subjective and remain constitutionally deficient for a regulation enforceable by criminal proceedings. The Agency reevaluated the definitions and concluded that they are sufficiently clear that the owners or operators subject to the amendments can reasonably be expected to understand these terms. Owners or operators should be able to identify covered material and comply with the regulations on the basis of the definitions supplied.

Comments were made suggesting the Agency describe more specifically a proper wetting operation. The purpose of the wetting requirements is to reduce the amount of asbestos dust generated during demolition operations. Many different procedures would accomplish this; therefore, the Agency believes that specifying such procedures is neither necessary nor appropriate. A new definition of "adequately wetted" was added to the regulations promulgated herein. The Agency believes that owners or operators of demolition operations are familiar with proper wetting procedures.

Two comments were made stating that the proposed demolition and renovation amendments are not emission standards and that asbestos emissions must be proved in determining compliance with the regulations. Congress has specified that EPA should set emission standards for hazardous air pollutants. EPA, charged with implementing this requirement, has determined that the term "emission standard" includes work practice requirements designed to limit emissions. The position taken by the Administrator on this issue in the promulgation of the original regulations on asbestos on April 6, 1973 (38 FR 8820) is unchanged here. The demolition and renovation regulations require certain work procedures to be followed. These methods of control are required because of the impossibility at this time of prescribing and enforcing allowable numerical concentrations or mass emission limitations. One difficulty in prescribing a numerical emission standard is the relative inaccuracy of asbestos analytical methods. Dr. Arnold Brown, testifying in a recent court case involving asbestos emissions [*United States et al.* v. *Reserve Mining Co. et al.*, 498 F.2d 1073, 1079, (8th Cir., 1974)] stated, "It is reasonable to assume an error in the count of fibers in both water and air of at least nine times on the high side to one-ninth on the low side." Further testifying on the same subject, Dr. Brown stated, ". . . I do not recall having been exposed to a procedure with an error this large, and which people have seriously proposed a number based on this very poor procedure." Moreover, there is no place to measure the total emissions from a demolition or renovation operation. The Agency has determined that violations of the work practices specified in the demolition section will result in emissions of asbestos. Considering these facts, the prescription of work practices is not only a legally permissible form of an emission standard, but also the only practical and reasonable form.

Waste Disposal. A number of commentators questioned the relationship between the proposed no-visible-emissions requirements in the proposed asbestos waste disposal provisions and the alternative methods for complying with the requirement. The following points were included in the comments:

1. Can any of a variety of waste disposal methods be used to meet the no-visible-emissions limit?

2. Various other methods of disposal should be specified as alternatives.

3. The inclusion of a no-visible-emissions requirement in portions of the alternative methods of compliance is a paradox.

4. Various alternatives are either not feasible or are unnecessary for some specific waste disposal operations.

As stated in §§ 61.22 (j) and (k) of the proposed and promulgated amendments, a requirement for affected sources that dispose of asbestos waste is no visible emissions during waste disposal operations. This provides affected sources flexibility in developing and using those disposal techniques most suitable to individual needs. The Agency recognizes that the best available disposal methods for some of the sources may not be capable of preventing visible emissions during a minor portion of some of the disposal operations. Therefore, alternative methods of compliance that represent the best available disposal methods have been included in the regulations. Sources are not required to use these methods; they may use other methods that achieve no visible emissions. However, sources may elect to use one of the specified alternatives. Some of these alternatives result in no visible emissions; others may not. For those alternative methods that may not be capable of preventing visible emissions during all portions of the waste disposal process, a requirement has nevertheless been included that there be no visible emissions from those portions of the process that can achieve this performance level. The listing of a particular method of waste disposal as an alternative method of compliance does not imply that the method is universally applicable or that the use of the method is necessary to achieve no visible emissions.

Some comments questioned whether the proposed amendments would apply to asbestos waste disposal sites that were inactivated prior to the publication of the proposed amendments. Regulations established under section 112 of the Act are applicable to both existing sources and new sources. The amendments cover previously inactivated sites as well as sites that become inactive in the future. However, the proposed amendments have been revised as discussed in "Changes to the Proposed Amendments" so that only owners of sites which have been operated by asbestos mills, manufacturing plants, and fabricating plants subject to the asbestos standard must comply with the asbestos amendments proposed herein for inactive asbestos waste disposal sites.

Several commentators suggested that certain types of asbestos waste disposal sites should be excluded from the proposed amendments, depending upon the the rate at which asbestos waste is deposited at the site, the percentage of the total waste that is asbestos, the friability of the asbestos waste, and the extent to which the site is in active operation. These comments were considered, but no changes in the proposed amendments were made as a result of the Agency's reevaluation. It would be extremely difficult to enforce regulations that depend on the rate or asbestos content of waste deposition. Further, the provisions promulgated herein shift the focus of the waste disposal requirements away from the site operator to the generator of the waste. Because of this, the burden of the requirements on a waste disposal site operator who accepts only a very small quantity of asbestos waste, and who the commentators desire to exclude from the regulations, is largely removed.

A comment was made that the proposed amendments could cause considerable hardship to small users of asbestos because some waste disposal sites may no longer accept asbestos wastes. There are an estimated 5,000 waste disposal sites in the U.S. which meet the standards of a sanitary landfill. A properly operated sanitary landfill complies with the soil-covering requirements of the amendments, and therefore will be affected only slightly by handling asbestos wastes. Accordingly, the Agency believes that small manufacturers and users of asbestos will not encounter severe problems in complying with the amendments for waste disposal sites.

Two commentators were concerned that the proposed waste disposal provisions would cause serious problems in contract hauling arrangements; and in the use of private landfills, municipal landfills, and waste disposal sites leased by generators of the asbestos waste. Since the generator of the waste has the direct responsibility for compliance during the transport of waste and for disposing of the waste at a properly operated disposal site, the Agency believes that problems in contract hauling arrangements can be avoided if the generator institutes proper waste handling practices. The Agency also believes that

the deletion in the promulgated amendments of some of the proposed requirements for posting of warning signs will remove many of the potential problems that were of concern. Further changes to the proposed amendments were judged unnecessary because they impose few additional requirements on disposal sites, such as municipal sanitary landfill sites, that are properly operated.

A comment suggested that bags which previously held commercial asbestos should be exempt if the bags have been cleaned sufficiently so that shaking the bags will not generate visible emissions of asbestos particulate matter. Even if such wastes do not produce visible emissions during the subsequent processing, transporting and depositing operations at a waste disposal site, there is a need for ensuring proper ultimate waste disposal because such bags still are likely to contain residual asbestos. The Agency believes that regulations are needed for this purpose and also for the purpose of ensuring that emissions from the cited method of cleaning bags are properly controlled. Accordingly, the disposal of bags that have been cleaned in the manner described has not been exempted from the amendments promulgated herein.

Comments were received which stated that the proposed waste disposal provisions would probably preclude the disposal of waste asbestos cement pipe in commercial landfills. It is the Agency's judgment that commercial landfills which comply with the regulations will be available. Further, the pipe crushing operation that is conventionally carried out during compaction at the disposal site can alternatively be performed and controlled by gas cleaning equipment at a stationary crusher.

Mercury.

Changes to Proposed Amendments

The proposed definition of "sludge dryer" has been revised to indicate more clearly that only sludge drying operations that are directly heated by combustion gases are covered by the amendment. The amendment does not apply to devices that are indirectly heated, such as secondary mercury recovery furnaces.

A comment suggested that daily sludge sampling and analysis should be required to reveal potential variations in mercury content of the sludge. The daily averages of sludge mercury content are not expected to vary significantly, and the Agency believes that the added cost to the owners or operators of such sources for daily sampling and analysis of sludge is not justified. Variations in mercury concentration of sludge can occur over longer periods of time, however, and a requirement has been added that all facilities for which emissions are in excess of 1600 grams per day as determined by the initial compliance test must monitor on a yearly basis with the sludge sampling method. In addition, the Agency has authority to request sludge sampling and analysis, or stack sampling, and will exercise this authority whenever there are indications that a change in mercury concentration of the sludge has occurred that would significantly increase mercury emissions.

One commentator suggested several revisions to procedures in the proposed sludge testing method, Method 105. The procedures were reevaluated, and the method has been changed where appropriate. The proposed section 3.1.3 of Method 105 specified a 10 percent solution of stannous chloride as an alternative to stannous sulfate. One comment stated that it was inappropriate to require any solution percentage. The Agency agrees, and the requirement has been deleted. Another comment suggested that the required use of mercuric chloride of Bureau of Standards purity to prepare the mercury stock solution is not necessary because the precision of the method does not demand such purity. The Agency agrees with this comment, and the method has been changed to permit the use of reagent grade mercuric chloride. The comment was made that mercuric solutions should not be prepared in plastic containers. The Agency is in general agreement with this and a statement to this effect has been added to Method 105. Section 4.1.1 of the method specifies that the, ". . . sampling devices, glassware and reagents should be ascertained free of significant amounts of mercury." A major source of mercury contamination occurs when sample solutions and reagents come into contact with mercury-contaminated containers. A comment indicated that a specific quantity should be stated to indicate how much mercury is considered "significant." The Agency believes that the specification of an amount of mercury contamination is inappropriate because such an amount would be very difficult to measure. The mercury contamination of containers can be reduced to an insignificant amount by properly cleaning such containers before use. The proposed paragraph has therefore been changed to specify that sample containers shall be properly cleaned before use by rinsing with nitric acid, followed by rinsing with distilled water. Another comment suggested that the possible interferences with the analysis of mercury in sludge should be delineated and that preventative measures should be given. In response, two references in which such interferences are discussed have been added to Method 105.

Additional Comments

The Agency has determined that an ambient air mercury concentration of 1 microgram per cubic meter averaged over a 30-day period will protect the public health with an ample margin of safety. The maximum allowable mercury emission for sludge incineration and drying plants was calculated, by use of meteorological modeling techniques using restrictive dispersion conditions, that would not result in this ambient concentration being exceeded. The resulting maximum allowable emission is 3200 grams of mercury per day. Numerous comments were received that questioned the methodology used to calculate this emission limitation. Several comments questioned the derivation of the ambient concentration of 1 microgram per cubic meter, 30-day average, and indicated that this level should be lower. The Agency evaluated these comments, but determined that no new information had been presented that had not been previously considered in the derivation of this allowable concentration. Another commentator stated that the restrictive meteorological conditions used for sewage sludge incineration and drying plants do not represent the "worst case" meteorological conditions, and discussed a specific existing facility as an example. The Agency analyzed this comment considering the meterological conditions and topography at the specific site mentioned in the comment and concluded that, even with a mercury emission of 3200 grams per day, the public will be protected with an ample margin of safety at the cited facility. A copy of the Agency response to this comment is available for inspection at the Public Information Reference Center, Room 2404 Waterside Mall, 401 M St., Wash., D.C. 20460. The Agency knows of no sludge incineration or drying facility where the ambient guideline level of one microgram of mercury per cubic meter, 30-day average, will be exceeded. The following comments stating that the proposed emission limit is too stringent or that additional studies are needed before promulgation were received:

1. The proposed emission limit provides an excessive safety factor for some plant locations.

2. The proposed emission limit should be based on plant size, allowing larger emissions for larger plants.

3. The intent of the proposed amendment seems to be to limit the size of new plants and require disposal of sludge by alternative methods.

4. The regulation seems to be excessively stringent in order to simplify the administration of the standard for multiple sources.

5. There is not enough information to justify promulgating the amendment at this time; the promulgation should be delayed until further studies are made.

In contrast, several comments suggested that the proposed emission limit was too lenient. Since the emission limitation is related to an ambient concentration, it would be inappropriate to allow higher emissions for larger plants. Concerning plant location, it would be impractical to specify a different emission limitation for each present or future plant location which reflected local meteorological conditions. Moreover, section 112 of the Act provides for a national standard, and the Administrator has set this standard at a level which will prevent exceeding the specified safe ambient level at all locations. The Agency determined that there is sufficient information to justify promulgating emission regulations for sludge incinerators and no data or information were presented that would justify changing the mercury emission limit of 3200 grams per day.

A comment was made that the impact of multiple sources of mercury emissions was not addressed in the derivation

of the national emission standard for mercury. While the standard does not include special provisions for multiple sources, it does provide a large safety factor at many sites and this provides a measure of protection against the multiple source problem. The Agency knows of no location where existing multiple sources of mercury will cause the ambient guideline level of one microgram of mercury per cubic meter, 30-day average, to be exceeded. The Agency must approve all new construction or modification of sources regulated by the mercury standard. During the review of such construction or modification, the Agency will assess the impact that the new or modified sources have on the ambient mercury concentration. If the Agency discovers a situation where a source can cause the guideline ambient concentration to be exceeded, the national emission standard will be reevaluated. In addition, local planning agencies have the capability to prevent multiple source pollution problems through proper land use planning. The Agency urges these local agencies to consider the impact of multiple sources on such problems as mercury air pollution when making planning decisions.

Comments were received that questioned whether all sludge incineration and drying plants are major sources of mercury emissions that must demonstrate compliance with the standard. All of these facilities have the potential to emit mercury; the amount of mercury that is emitted depends upon the mercury content of the sludge and the sludge incineration or drying rate. Accordingly, all such facilities must demonstrate compliance with the emission limitation promulgated herein.

A comment was received that the economic impact of the proposed amendments on some large facilities may be large, since there may be few or no alternatives for sludge disposal. The Agency estimates that the largest mercury emission from an existing sludge incinerator or dryer is approximately 500 grams per day, which is approximately one-sixth of the maximum allowable emission. The time period over which sludge generation would increase in excess of six-fold should provide sufficient lead time for planning an economically feasible alternate disposal method, if it is required. The Agency therefore does not foresee a significant economic impact for the near future at any sludge incineration or drying plant.

Several comments stated that other sources such as ore processing plants, mercury compound manufacturing plants, industrial waste incinerators, coal-fired power plants, and rooms painted with mercury-containing paints should be investigated and regulated if necessary. The Agency previously investigated mercury emissions from nonferrous smelting plants, secondary mercury production plants, coal-fired power plants, and solid waste incineration plants, and determined that these sources do not emit mercury in such quantities that they are likely to cause the ambient mercury concentration to exceed one microgram per cubic meter. The Agency has regulated all sources that may reasonably be expected to cause an ambient mercury concentration of as much as one microgram per cubic meter, 30-day average. However, the Agency will continue a policy of investigating any source of mercury that it has reason to believe has the potential to endanger the public health.

Another comment stated that the Agency should give specific suggestions, or references should be provided, for disposing of mercury-containing sludges on land in a manner that would protect water resources. The Agency's Office of Water and Hazardous Materials is preparing technical publications on various alternatives for the disposal of sludges, and such materials should be available in the near future.

Several comments were made on the mercury collection efficiency of water scrubbers. One commentator suggested that the mercury collection efficiency of individual water scrubbers should be assumed to be zero for purposes of determining compliance, until positively proven otherwise. Another commentator stated that the proposed sludge sampling method should take into account the amount of mercury that would be collected by a scrubber. The Agency has determined that the requirements of the standard are adequate. No credit for mercury removed by water scrubbers is allowed when compliance is determined by sludge sampling and analysis; however, if the mercury stack measurement method is used to determine compliance, only the amount of mercury emitted to the outside air is measured and any mercury collection by the system is taken into account. The Agency has determined that sludge sampling and analysis can be used as an alternative method to determine maximum mercury emissions, because it is sufficiently accurate. The method is also inexpensive when compared to a complete stack test.

The following comments were received which suggested changes to Method 105 for sludge sampling:

1. A 5 percent potassium permanganate solution is difficult to prepare, and a saturated solution should be required.

2. Potassium permanganate should be used to stabilize mercury solutions.

3. Hydroxylamine hydrochloride can be used in place of the uncommon salt sodium chloride-hydroxylamine sulfate to reduce excess potassium permanganate.

Solutions of 5 percent potassium permanganate can be prepared at room temperature. The Agency has no experience in using potassium permanganate to stabilize mercury solutions, and has not used hydroxylamine hydrochloride to reduce excess potassium permanganate. The method has proved to be satisfactory without the use of the suggested reagents. The Agency believes that the suggested changes are not necessary and the method has not been revised to accommodate these suggestions.

Environmental and Energy Impact

Environmental impact statements must accompany national emission standards for hazardous air pollutants approved for proposal after October 14, 1974. The amendments recommended for promulgation were approved for proposal prior to this date, and an environmental impact statement has not been prepared. The environmental impact of the standards has been assessed, however, and is discussed in the background information document (EPA-450/2-74-009a) for the proposed standards and in the preamble (39 FR 38064) to the proposed standards.

The energy impact resulting from the control of asbestos waste disposal operations at asbestos emission sources and at waste disposal sites is expected to be insignificant since this waste is already collected and deposited at waste disposal sites. Only a relatively small quantity of additional waste material is generated as a result of better control of particulate emissions from manufacturing and fabrication sources covered by the standard. The major energy impact of the amendments is that resulting from the operation of fabric filtration devices at manufacturing and fabrication plants. It is estimated that approximately 170 baghouses of 1000 acfm capacity will be required to comply with the amendments. The operation of these control devices will require the consumption of 2.5 million kilowatt hours per year, which is equivalent to 3900 barrels per year of Number 6 fuel oil at the power generating station. The energy impact resulting from the NESHAPS amendment is small and is justified by the increased control of asbestos emissions.

There is no energy impact that results from the regulation of mercury emissions from sludge incinerators and dryers.

Effective upon promulgation.

(Sec. 112 and 114 of the Clean Air Act, as amended (42 U.S.C. 1857c-7 and 9))

Dated: October 3, 1975.

JOHN QUARLES,
Acting Administrator.

Part 61 of Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

1. The table of sections is amended as follows:

Subpart A—General Provisions

Sec.

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61.17 Circumvention.

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Subpart B—National Emission Standard for Asbestos

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61.25 Waste disposal sites.

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Subpart E—National Emission Standard for Mercury

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61.54 Sludge sampling.
61.55 Emission monitoring.

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Appendix B—Test Methods

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Method 105—Method for determination of mercury in wastewater treatment plant sewage sludges.

2. The authority citation at the end of the table of sections for Part 61 is revised to read as follows:

AUTHORITY: Secs. 112 and 114 of the Clean Air Act, as amended by sec. 4(a) of Pub. L. 91-604, 84 Stat. 1678 (42 U.S.C. 1857c-7, 1857 c-9).

Subpart A—General Provisions

3. Section 61.14 is amended by revising paragraph (c), and adding paragraph (d). The revised and added paragraphs read as follows:

§ 61.14 Source test and analytical methods.

* * * * *

(c) The Administrator may, after notice to the owner or operator, withdraw approval of an alternative method granted under paragraphs (a), (b) or (d) of this section. Where the test results using an alternative method do not adequately indicate whether a source is in compliance with a standard, the Administrator may require the use of the reference method or its equivalent.

(d) Method 105 in Appendix B to this part is hereby approved by the Administrator as an alternative method for sources subject to § 61.52(b).

4. A new § 61.17 is added to subpart A as follows:

§ 61.17 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment, process, or method, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous dilutants to achieve compliance with a visible emissions standard, and the piecemeal carrying out of an operation to avoid coverage by a standard that applies only to operations larger than a specified size.

Subpart B—National Emission Standard for Asbestos

5. Section 61.21 is amended by revising paragraph (j) and adding paragraphs (k), (l), (m), (n), (o), (p), (q), (r), (s), (t), (u), (v), and (w). The revised and added paragraphs read as follows:

§ 61.21 Definitions.

* * * * * * *

(j) "Demolition" means the wrecking or taking out of any load-supporting structural member and any related removing or stripping of friable asbestos materials.

(k) "Friable asbestos material" means any material that contains more than 1 percent asbestos by weight and that can be crumbled, pulverized, or reduced to powder, when dry, by hand pressure.

(l) "Control device asbestos waste" means any asbestos-containing waste material that is collected in a pollution control device.

(m) "Renovation" means the removing or stripping of friable asbestos material used to insulate or fireproof any pipe, duct, boiler, tank, reactor, turbine, furnace, or structural member. Operations in which load-supporting structural members are wrecked or taken out are excluded.

(n) "Planned renovation" means a renovation operation, or a number of such operations, in which the amount of friable asbestos material that will be removed or stripped within a given period of time can be predicted. Operations that are individually non-scheduled are included, provided a number of such operations can be predicted to occur during a given period of time based on operating experience.

(o) "Emergency renovation" means a renovation operation that results from a sudden, unexpected event, and is not a planned renovation. Operations necessitated by non-routine failures of equipment are included.

(p) "Adequately wetted" means sufficiently mixed or coated with water or an aqueous solution to prevent dust emissions.

(q) "Removing" means taking out friable asbestos materials used to insulate or fireproof any pipe, duct, boiler, tank, reactor, turbine, furnace, or structural member from any building, structure, facility, or installation.

(r) "Stripping" means taking off friable asbestos materials used for insulation or fireproofing from any pipe, duct, boiler, tank, reactor, turbine, furnace, or structural member.

(s) "Fabricating" means any processing of a manufactured product containing commercial asbestos, with the exception of processing at temporary sites for the construction or restoration of buildings, structures, facilities or installations.

(t) "Inactive waste disposal site" means any disposal site or portion thereof where additional asbestos-containing waste material will not be deposited and where the surface is not disturbed by vehicular traffic.

(u) "Active waste disposal site" means any disposal site other than an inactive site.

(v) "Roadways" means surfaces on which motor vehicles travel including, but not limited to, highways, roads, streets, parking areas, and driveways.

(w) "Asbestos-containing waste material" means any waste which contains commercial asbestos and is generated by a source subject to the provisions of this subpart, including asbestos mill tailings, control device asbestos waste, friable asbestos waste material, and bags or containers that previously contained commercial asbestos.

6. Section 61.22 is amended by amending paragraphs (c) and (e), revising paragraphs (b), (d), (f), and (g) and adding paragraphs (h), (i), (j), (k), and (l). The revised and added paragraphs read as follows:

§ 61.22 Emission standard.

* * * * *

(b) Roadways: The surfacing of roadways with asbestos tailings or with asbestos-containing waste that is generated by any source subject to paragraphs (c), (d), (e) or (h) of this section is prohibited, except for temporary roadways on an area of asbestos ore deposits. The deposition of asbestos tailings or asbestos-containing waste on roadways covered with snow or ice is considered "surfacing."

(c) Manufacturing: There shall be no visible emissions to the outside air, except as provided in paragraph (f) of this section, from any of the following operations if they use commercial asbestos or from any building or structure in which such operations are conducted.

* * * * *

(10) The manufacture of shotgun shells.

(11) The manufacture of asphalt concrete.

(d) Demolition and renovation: The requirements of this paragraph shall apply to any owner or operator of a demolition or renovation operation who intends to demolish any institutional, commercial, or industrial building (including apartment buildings having more than four dwelling units), structure, facility, installation, or portion thereof which contains any pipe, duct, boiler, tank, reactor, turbine, furnace, or structural member that is insulated or fireproofed with friable asbestos material, except as provided in paragraph (d)(1) of this section; or who intends to renovate any institutional, commercial, or industrial building, structure, facility, installation, or portion thereof where more than 80 meters (ca. 260 feet) of pipe insulated or fireproofed with friable asbestos material are stripped or removed, or more than 15 square meters (ca. 160 square feet) of friable asbestos material used to insulate or fireproof any duct, boiler, tank, reactor, turbine, furnace, or structural member are stripped or removed.

(1)(i) The owner or operator of a demolition operation is exempted from the requirements of this paragraph provided, (1) the amount of friable asbestos material in the building or portion thereof to be demolished is less than 80 meters (ca. 260 feet) used to insulate pipes, and less than 15 square meters (ca. 160 square feet) used to insulate or fireproof any duct, boiler, tank, reactor, turbine, furnace, or structural member, and (2) the notification requirements of paragraph (d)(1)(ii) are met.

(ii) Written notification shall be postmarked or delivered to the Administrator at least 20 days prior to commencement of demolition and shall include the information required by paragraph (d)(2) of this section, with the exception of the information required by paragraphs (d)(2)(iii), (vi), (vii), (viii), and (ix), and shall state the measured or estimated amount of friable asbestos material used for insulation and fireproofing which is present. Techniques of estimation shall be explained.

(2) Written notice of intention to demolish or renovate shall be provided to the Administrator by the owner or operator of the demolition or renovation operation. Such notice shall be postmarked or delivered to the Administrator at least 10 days prior to commencement of demo-

lition, or as early as possible prior to commencement of emergency demolition subject to paragraph (d)(6) of this section, and as early as possible prior to commencement of renovation. Such notice shall include the following information:

(i) Name of owner or operator.

(ii) Address of owner or operator.

(iii) Description of the building, structure, facility, or installation to be demolished or renovated, including the size, age, and prior use of the structure, and the approximate amount of friable asbestos material used for insulation and fireproofing.

(iv) Address or location of the building, structure, facility, or installation.

(v) Scheduled starting and completion dates of demolition or renovation.

(vi) Nature of planned demolition or renovation and method(s) to be employed.

(vii) Procedures to be employed to meet the requirements of this paragraph and paragraph (j) of this section.

(viii) The name and address or location of the waste disposal site where the friable asbestos waste will be deposited.

(ix) Name, title, and authority of the State or local governmental representative who has ordered a demolition which is subject to paragraph (d)(6) of this section.

(3)(i) For purposes of determining whether a planned renovating operation constitutes a renovation within the meaning of this paragraph, the amount of friable asbestos material to be removed or stripped shall be:

(A) For planned renovating operations involving individually non-scheduled operations, the additive amount of friable asbestos material that can be predicted will be removed or stripped at a source over the maximum period of time for which a prediction can be made. The period shall be not less than 30 days and not longer than one year.

(B) For each planned renovating operation not covered by paragraph (d)(3)(i)(A), the total amount of friable asbestos material that can be predicted will be removed or stripped at a source.

(ii) For purposes of determining whether an emergency renovating operation constitutes a renovation within the meaning of this paragraph, the amount of friable asbestos material to be removed or stripped shall be the total amount of friable asbestos material that will be removed or stripped as a result of the sudden, unexpected event that necessitated the renovation.

(4) The following procedures shall be used to prevent emissions of particulate asbestos material to outside air:

(i) Friable asbestos materials, used to insulate or fireproof any pipe, duct, boiler, tank, reactor, turbine, furnace, or structural member, shall be removed from any building, structure, facility or installation subject to this paragraph. Such removal shall occur before wrecking or dismantling of any portion of such building, structure, facility, or installation that would break up the friable asbestos materials and before wrecking or dismantling of any other portion of such building, structure, facility, or installation that would preclude access to such materials for subsequent removal. Removal of friable asbestos materials used for insulation or fireproofing of any pipe, duct, or structural member which are encased in concrete or other similar structural material is not required prior to demolition, but such material shall be adequately wetted whenever exposed during demolition.

(ii) Friable asbestos materials used to insulate or fireproof pipes, ducts, boilers, tanks, reactors, turbines, furnaces, or structural members shall be adequately wetted during stripping, except as provided in paragraphs (d)(4)(iv), (d)(4)(vi) or (d)(4)(vii) of this section.

(iii) Pipes, ducts, boilers, tanks, reactors, turbines, furnaces, or structural members that are insulated or fireproofed with friable asbestos materials may be taken out of any building, structure, facility, or installation subject to this paragraph as units or in sections provided the friable asbestos materials exposed during cutting or disjointing are adequately wetted during the cutting or disjointing operation. Such units shall not be dropped or thrown to the ground, but shall be carefully lowered to ground level.

(iv) The stripping of friable asbestos materials used to insulate or fireproof any pipe, duct, boiler, tank, reactor, turbine, furnace, or structural member that has been removed as a unit or in sections as provided in paragraph (d)(4)(iii) of this section shall be performed in accordance with paragraph (d)(4)(ii) of this section. Rather than comply with the wetting requirement, a local exhaust ventilation and collection system may be used to prevent emissions to the outside air. Such local exhaust ventilation systems shall be designed and operated to capture the asbestos particulate matter produced by the stripping of friable asbestos material. There shall be no visible emissions to the outside air from such local exhaust ventilation and collection systems except as provided in paragraph (f) of this section.

(v) All friable asbestos materials that have been removed or stripped shall be adequately wetted to ensure that such materials remain wet during all remaining stages of demolition or renovation and related handling operations. Such materials shall not be dropped or thrown to the ground or a lower floor. Such materials that have been removed or stripped more than 50 feet above ground level, except those materials removed as units or in sections, shall be transported to the ground via dust-tight chutes or containers.

(vi) Except as specified below, the wetting requirements of this paragraph are suspended when the temperature at the point of wetting is below 0°C (32°F). When friable asbestos materials are not wetted due to freezing temperatures, such materials on pipes, ducts, boilers, tanks, reactors, turbines, furnaces, or structural members shall, to the maximum extent possible, be removed as units or in sections prior to wrecking. In no case shall the requirements of paragraphs (d)(4)(iv) or (d)(4)(v) be suspended due to freezing temperatures.

(vii) For renovation operations, local exhaust ventilation and collection systems may be used, instead of wetting as specified in paragraph (d)(4)(ii), to prevent emissions of particulate asbestos material to outside air when damage to equipment resulting from the wetting would be unavoidable. Upon request and supply of adequate information, the Administrator will determine whether damage to equipment resulting from wetting to comply with the provisions of this paragraph would be unavoidable. Such local exhaust ventilation systems shall be designed and operated to capture the asbestos particulate matter produced by the stripping and removal of friable asbestos material. There shall be no visible emissions to the outside air from such local exhaust ventilation and collection systems, except as provided in paragraph (f) of this section.

(5) Sources subject to this paragraph are exempt from the requirements of §§ 61.05(a), 61.07, and 61.09.

(6) The demolition of a building, structure, facility, or installation, pursuant to an order of an authorized representative of a State or local governmental agency, issued because that building is structurally unsound and in danger of imminent collapse is exempt from all but the following requirements of paragraph (d) of this section:

(i) The notification requirements specified by paragraph (d)(2) of this section;

(ii) The requirements on stripping of friable asbestos materials from previously removed units or sections as specified in paragraph (d)(4)(iv) of this section;

(iii) The wetting, as specified by paragraph (d)(4)(v) of this section, of friable asbestos materials that have been removed or stripped;

(iv) The portion of the structure being demolished that contains friable asbestos materials shall be adequately wetted during the wrecking operation.

(e) * * *

(2) Any owner or operator who intends to spray asbestos materials which contain more than 1 percent asbestos on a dry weight basis to insulate or fireproof equipment and machinery shall report such intention to the Administrator at least 20 days prior to the commencement of the spraying operation. Such report shall include the following information:

* * *

(f) Rather than meet the no-visible-emission requirements as specified by paragraphs (a), (c), (d), (e), (h), (j), and (k) of this section, an owner or operator may elect to use the methods specified by § 61.23 to clean emissions containing particulate asbestos material before such emissions escape to, or are vented to, the outside air.

(g) Where the presence of uncombined water is the sole reason for failure to meet the no-visible-emission requirement of paragraphs (a), (c), (d), (e),

(h), (j), or (k) of this section, such failure shall not be a violation of such emission requirements.

(h) Fabricating: There shall be no visible emissions to the outside air, except as provided in paragraph (f) of this section, from any of the following operations if they use commercial asbestos or from any building or structure in which such operations are conducted.

(1) The fabrication of cement building products.

(2) The fabrication of friction products, except those operations that primarily install asbestos friction materials on motor vehicles.

(3) The fabrication of cement or silicate board for ventilation hoods; ovens; electrical panels; laboratory furniture; bulkheads, partitions and ceilings for marine construction; and flow control devices for the molten metal industry.

(i) Insulating: Molded insulating materials which are friable and wet-applied insulating materials which are friable after drying, installed after the effective date of these regulations, shall contain no commercial asbestos. The provisions of this paragraph do not apply to insulating materials which are spray applied; such materials are regulated under § 61.22(e).

(j) Waste disposal for manufacturing, fabricating, demolition, renovation and spraying operations: The owner or operator of any source covered under the provisions of paragraphs (c), (d), (e), or (h) of this section shall meet the following standards:

(1) There shall be no visible emissions to the outside air, except as provided in paragraph (j)(3) of this section, during the collection; processing, including incineration; packaging; transporting; or deposition of any asbestos-containing waste material which is generated by such source.

(2) All asbestos-containing waste material shall be deposited at waste disposal sites which are operated in accordance with the provisions of § 61.25.

(3) Rather than meet the requirement of paragraph (j)(1) of this section, an owner or operator may elect to use either of the disposal methods specified under (j)(3)(i) and (ii) of this section, or an alternative disposal method which has received prior approval by the Administrator:

(i) Treatment of asbestos-containing waste material with water:

(A) Control device asbestos waste shall be thoroughly mixed with water into a slurry and other asbestos-containing waste material shall be adequately wetted. There shall be no visible emissions to the outside air from the collection, mixing and wetting operations, except as provided in paragraph (f) of this section.

(B) After wetting, all asbestos-containing waste material shall be sealed into leak-tight containers while wet, and such containers shall be deposited at waste disposal sites which are operated in accordance with the provisions of § 61.25.

(C) The containers specified under paragraph (j)(3)(i)(B) of this section shall be labeled with a warning label that states:

CAUTION

Contains Asbestos
Avoid Opening or Breaking Container
Breathing Asbestos is Hazardous
to Your Health

Alternatively, warning labels specified by Occupational Safety and Health Standards of the Department of Labor, Occupational Safety and Health Administration (OSHA) under 29 CFR 1910.93a(g)(2)(ii) may be used.

(ii) Processing of asbestos-containing waste material into non-friable forms:

(A) All asbestos-containing waste material shall be formed into non-friable pellets or other shapes and deposited at waste disposal sites which are operated in accordance with the provisions of § 61.25.

(B) There shall be no visible emissions to the outside air from the collection and processing of asbestos-containing waste material, except as specified in paragraph (f) of this section.

(4) For the purposes of this paragraph (j), the term all asbestos-containing waste material as applied to demolition and renovation operations covered by paragraph (d) of this section includes only friable asbestos waste and control device asbestos waste.

(k) Waste disposal for asbestos mills: The owner or operator of any source covered under the provisions of paragraph (a) of this section shall meet the following standard:

(1) There shall be no visible emissions to the outside air, except as provided in paragraph (k)(3) of this section, during the collection, processing, packaging, transporting or deposition of any asbestos-containing waste material which is generated by such source.

(2) All asbestos-containing waste material shall be deposited at waste disposal sites which are operated in accordance with the provisions of § 61.25.

(3) Rather than meet the requirement of paragraph (k)(1) of this section, an owner or operator may elect to meet the following requirements in paragraphs (k)(3)(i) and (ii), or use an alternative disposal method which has received prior approval by the Administrator:

(i) There shall be no visible emissions to the outside air from the transfer of control device asbestos waste to the tailings conveyor, except as provided in paragraph (f) of this section. Such waste shall be subsequently processed either as specified in paragraph (k)(3)(ii) of this section or as specified in paragraph (j)(3) of this section.

(ii) All asbestos-containing waste material shall be adequately mixed, with a wetting agent recommended by the manufacturer of the agent to effectively wet dust and tailings, prior to deposition at a waste disposal site. Such agent shall be used as recommended for the particular dust by the manufacturer of the agent. There shall be no discharge of visible emissions to the outside air from the wetting operation except as specified in paragraph (f) of this section. Wetting may be suspended when the ambient temperature at the waste disposal site is less than −9.5°C (ca. 15°F). The ambient air temperature shall be determined by an appropriate measurement method with an accuracy of ±1°C (±2°F) and recorded at least at hourly intervals during the period that the operation of the wetting system is suspended. Records of such temperature measurements shall be retained at the source for a minimum of two years and made available for inspection by the Administrator.

(l) The owner of any inactive waste disposal site, which was operated by sources covered under § 61.22 (a), (c) or (h) and where asbestos-containing waste material produced by such sources was deposited, shall meet the following standards:

(1) There shall be no visible emissions to the outside air from an inactive waste disposal site subject to this paragraph, except as provided in paragraph (l)(5) of this section.

(2) Warning signs shall be displayed at all entrances, and along the property line of the site or along the perimeter of the sections of the site where asbestos-containing waste material was deposited, at intervals of 100 m (ca. 330 ft) or less, except as specified in paragraph (l)(4) of this section. Signs shall be posted in such a manner and location that a person may easily read the legend. The warning signs required by this paragraph shall conform to the requirements of 20" x 14" upright format signs specified in 29 CFR 1910.145(d)(4) and this paragraph. The signs shall display the following legend in the lower panel, with letter sizes and styles of a visibility at least equal to those specified in this paragraph.

LEGEND

ASBESTOS WASTE DISPOSAL SITE

DO NOT CREATE DUST

Breathing Asbestos is Hazardous
to Your Health

Notation

1" Sans Serif, Gothic or Block

¼" Sans Serif, Gothic or Block

14 Point Gothic

Spacing between lines shall be at least equal to the height of the upper of the two lines.

(3) The perimeter of the site shall be fenced in a manner adequate to deter access by the general public, except as specified in paragraph (l)(4) of this section.

(4) Warning signs and fencing are not required where the requirements of paragraphs (l)(5)(i) or (ii) of this section are met, or where a natural barrier adequately deters access by the general public. Upon request and supply of appropriate information, the Administrator will determine whether a fence or a natural barrier adequately deters access to the general public.

(5) Rather than meet the requirement of paragraph (l)(1) of this section, an owner may elect to meet the requirements of this paragraph or may use an alternative control method for emissions from inactive waste disposal sites which

has received prior approval by the Administrator.

(i) The asbestos-containing waste material shall be covered with at least 15 centimeters (ca. 6 inches) of compacted non-asbestos-containing material, and a cover of vegetation shall be grown and maintained on the area adequate to prevent exposure of the asbestos-containing waste material; or

(ii) The asbestos-containing waste material shall be covered with at least 60 centimeters (ca. 2 feet) of compacted non-asbestos-containing material and maintained to prevent exposure of the asbestos-containing waste; or

(iii) For inactive waste disposal sites for asbestos tailings, a resinous or petroleum-based dust suppression agent which effectively binds dust and controls wind erosion shall be applied. Such agent shall be used as recommended for the particular asbestos tailings by the dust suppression agent manufacturer. Other equally effective dust suppression agents may be used upon prior approval by the Administrator. For purposes of this paragraph, waste crankcase oil is not considered a dust suppression agent.

7. The first sentence in § 61.23 is revised as follows:

§ 61.23 Air-Cleaning.

If air-cleaning is elected, as permitted by §§ 61.22(f) and 61.22(d)(4)(iv), the requirements of this section must be met.

* * *

8. The first sentence in § 61.24 is revised and redesignated as paragraph (e) and new paragraphs (c) and (d) are added as follows:

§ 61.24 Reporting.

* * * * *

(c) For sources subject to §§ 61.22(j) and 61.22(k):

(1) A brief description of each process that generates asbestos-containing waste material.

(2) The average weight of asbestos-containing waste material disposed of, measured in kg/day.

(3) The emission control methods used in all stages of waste disposal.

(4) The type of disposal site or incineration site used for ultimate disposal, the name of the site operator, and the name and location of the disposal site.

(d) For sources subject to § 61.22(l):

(1) A brief description of the site.

(2) The method or methods used to comply with the standard, or alternative procedures to be used.

(e) Such information shall accompany the information required by § 61.10. The information described in this section shall be reported using the format of Appendix A of this part.

9. A new section 61.25 is added to subpart B as follows:

§ 61.25 Waste disposal sites.

In order to be an acceptable site for disposal of asbestos-containing waste material under § 61.22 (j) and (k), an active waste disposal site shall meet the requirements of this section.

(a) There shall be no visible emissions to the outside air from any active waste disposal site where asbestos-containing waste material has been deposited, except as provided in paragraph (e) of this section.

(b) Warning signs shall be displayed at all entrances, and along the property line of the site or along the perimeter of the sections of the site where asbestos-containing waste material is deposited, at intervals of 100 m (ca. 330 ft) or less except as specified in paragraph (d) of this section. Signs shall be posted in such a manner and location that a person may easily read the legend. The warning signs required by this paragraph shall conform to the requirements of 20" x 14" upright format signs specified in 29 CFR 1910.145(d)(4) and this paragraph. The signs shall display the following legend in the lower panel, with letter sizes and styles of a visibility at least equal to those specified in this paragraph.

LEGEND

ASBESTOS WASTE DISPOSAL SITE

Do Not Create Dust

Breathing Asbestos
is Hazardous to Your Health

Notation

1" Sans Serif, Gothic or Block

¾" Sans Serif, Gothic or Block

14 Point Gothic

Spacing between lines shall be at least equal to the height of the upper of the two lines.

(c) The perimeter of the disposal site shall be fenced in order to adequately deter access to the general public except as specified in paragraph (d) of this section.

(d) Warning signs and fencing are not required where the requirements of paragraph (e)(1) of this section are met, or where a natural barrier adequately deters access to the general public. Upon request and supply of appropriate information, the Administrator will determine whether a fence or a natural barrier adequately deters access to the general public.

(e) Rather than meet the requirement of paragraph (a) of this section, an owner or operator may elect to meet the requirements of paragraph (e)(1) or (e)(2) of this section, or may use an alternative control method for emissions from active waste disposal sites which has received prior approval by the Administrator.

(1) At the end of each operating day, or at least once every 24-hour period while the site is in continuous operation, the asbestos-containing waste material which was deposited at the site during the operating day or previous 24-hour period shall be covered with at least 15 centimeters (ca. 6 inches) of compacted non-asbestos-containing material.

(2) At the end of each operating day, or at least once every 24-hour period while the disposal site is in continuous operation, the asbestos-containing waste material which was deposited at the site during the operating day or previous 24-hour period shall be covered with a resinous or petroleum-based dust suppression agent which effectively binds dust and controls wind erosion. Such agent shall be used as recommended for the particular dust by the dust suppression agent manufacturer. Other equally effective dust suppression agents may be used upon prior approval by the Administrator. For purposes of this paragraph, waste crankcase oil is not considered a dust suppression agent.

Subpart E—National Emission Standard for Mercury

10. Section 61.50 is revised to read as follows:

§ 61.50 Applicability.

The provisions of this subpart are applicable to those stationary sources which process mercury ore to recover mercury, use mercury chlor-alkali cells to produce chlorine gas and alkali metal hydroxide, and incinerate or dry wastewater treatment plant sludge.

11. Section 61.51 is amended by adding paragraphs (l) and (m) as follows:

§ 61.51 Definitions.

* * * * *

(l) "Sludge" means sludge produced by a treatment plant that processes municipal or industrial waste waters.

(m) "Sludge dryer" means a device used to reduce the moisture content of sludge by heating to temperatures above 65°C (ca. 150°F) directly with combustion gases.

12. Section 61.52 is revised to read as follows:

§ 61.52 Emission standard.

(a) Emissions to the atmosphere from mercury ore processing facilities and mercury cell chlor-alkali plants shall not exceed 2300 grams of mercury per 24-hour period.

(b) Emissions to the atmosphere from sludge incineration plants, sludge drying plants, or a combination of these that process wastewater treatment plant sludges shall not exceed 3200 grams of mercury per 24-hour period.

13. Section 61,53 is amended by adding paragraph (d) as follows:

§ 61.53 Stack sampling.

* * * * *

(d) Sludge incineration and drying plants.

(1) Unless a waiver of emission testing is obtained under § 61.13, each owner or operator of a source subject to the standard in § 61.52(b) shall test emissions from that source. Such tests shall be conducted in accordance with the procedures set forth either in paragraph (d) of this section or in § 61.54.

(2) Method 101 in Appendix B to this part shall be used to test emissions as follows:

(i) The test shall be performed within 90 days of the effective date of these regulations in the case of an existing source or a new source which has an initial startup date preceding the effective date.

(ii) The test shall be performed within 90 days of startup in the case of a new source which did not have an initial startup date preceding the effective date.

(3) The Administrator shall be notified at least 30 days prior to an emission test, so that he may at his option observe the test.

(4) Samples shall be taken over such a period or periods as are necessary to determine accurately the maximum emissions which will occur in a 24-hour period. No changes shall be made in the operation which would potentially increase emissions above the level determined by the most recent stack test, until the new emission level has been estimated by calculation and the results reported to the Administrator.

(5) All samples shall be analyzed, and mercury emissions shall be determined within 30 days after the stack test. Each determination shall be reported to the Administrator by a registered letter dispatched before the close of the next business day following such determination.

(6) Records of emission test results and other data needed to determine total emissions shall be retained at the source and shall be made available, for inspection by the Administrator, for a minimum of 2 years.

14. Sections 61.54 and 61.55 are added as follows:

§ 61.54 Sludge sampling.

(a) As an alternative means for demonstrating compliance with § 61.52 (b), an owner or operator may use Method 105 of Appendix B and the procedures specified in this section.

(1) A sludge test shall be conducted within 90 days of the effective date of these regulations in the case of an existing source or a new source which has an initial startup date preceding the effective date; or

(2) A sludge test shall be conducted within 90 days of startup in the case of a new source which did not have an initial startup date preceding the effective date.

(b) The Administrator shall be notified at least 30 days prior to a sludge sampling test, so that he may at his option observe the test.

(c) Sludge shall be sampled according to paragraph (c)(1) of this section, sludge charging rate for the plant shall be determined according to paragraph (c)(2) of this section, and the sludge analysis shall be performed according to paragraph (c)(3) of this section.

(1) The sludge shall be sampled after dewatering and before incineration or drying, at a location that provides a representative sample of the sludge that is charged to the incinerator or dryer. Eight consecutive grab samples shall be obtained at intervals of between 45 and 60 minutes and thoroughly mixed into one sample. Each of the eight grab samples shall have a volume of at least 200 ml but not more than 400 ml. A total of three composite samples shall be obtained within an operating period of 24 hours. When the 24-hour operating period is not continuous, the total sampling period shall not exceed 72 hours after the first grab sample is obtained. Samples shall not be exposed to any condition that may result in mercury contamination or loss.

(2) The maximum 24-hour period sludge incineration or drying rate shall be determined by use of a flow rate measurement device that can measure the mass rate of sludge charged to the incinerator or dryer with an accuracy of ±5 percent over its operating range. Other methods of measuring sludge mass charging rates may be used if they have received prior approval by the Administrator.

(3) The handling, preparation, and analysis of sludge samples shall be accomplished according to Method 105 in Appendix B of this part.

(d) The mercury emissions shall be determined by use of the following equation:

$$E_{Hg} = 1 \times 10^{-3} cQ$$

where

E_{Hg} = Mercury emissions, g/day.
c = Mercury concentration of sludge on a dry solids basis, μg/g (ppm).
Q = Sludge charging rate, kg/day.

(e) No changes in the operation of a plant shall be made after a sludge test has been conducted which would potentially increase emissions above the level determined by the most recent sludge test, until the new emission level has been estimated by calculation and the results reported to the Administrator.

(f) All sludge samples shall be analyzed for mercury content within 30 days after the sludge sample is collected. Each determination shall be reported to the Administrator by a registered letter dispatched before the close of the next business day following such determination.

(g) Records of sludge sampling, charging rate determination and other data needed to determine mercury content of wastewater treatment plant sludges shall be retained at the source and made available, for inspection by the Administrator, for a minimum of 2 years.

§ 61.55 Emission monitoring.

(a) Wastewater treatment plant sludge incineration and drying plants. All such sources for which mercury emissions exceed 1600 g/day, demonstrated either by stack sampling according to § 61.53 or sludge sampling according to § 61.54, shall monitor mercury emissions at intervals of at least once per year by use of Method 105 of Appendix B, or the procedures specified in § 61.54(c) and (d). The results of monitoring shall be reported and retained according to § 61.53(d) (5) and (6), or § 61.54(f) and (g).

15. Appendix A is revised to a new reporting format, and sections (E) (C) and (I) (D) are added as follows:

APPENDIX A

National Emission Standards for Hazardous Air Pollutants

Compliance Status Information

I. SOURCE REPORT

INSTRUCTIONS: Owners or operators of sources of hazardous pollutants subject to the National Emission Standards for Hazardous Air Pollutants are required to submit the information contained in Section I to the appropriate U.S. Environmental Protection Agency Regional Office prior to 90 days after the effective date of any standards or amendments which require the submission of such information.

A list of regional offices is provided in §61.04.

A. SOURCE INFORMATION

1. Identification/Location - Indicate the name and address of each source.

1 2		3 4		5 8		9 13		0 0 0		0 0		1						
Region		State		County		Source Number		14 16		17 18		19						
20 22		23 26		27 Source Name 46														
AQCR #		City Code																
47 Street Address (Location of Plant) 66 80																		
Dup 1-18		19		20 City Name 34				State 35 39										
				40 State Regis. Number 54				55 58 NEDS X Ref.										
				59 SIC 62		FF 64		A/P 65		8 77 Staff 79				80				
Dup 1-18		5 19		CS 30		SIP 31		EC 49				80						

2. Contact - Indicate the name and telephone number of the owner or operator or other responsible official whom EPA may contact concerning this report.

Dup 1-18 41 19 20 21 Name 43

44 46 Area Code 47 Number 54 80

3. Source Description - Briefly state the nature of the source (e.g., "Chlor-alkali Plant" or "Machine Shop").

Dup 1-18 42 19 20 21 Description 50

51 Continued 79 80

4. Alternative Mailing Address - Indicate an alternative mailing address if correspondence is to be directed to a location different than that specified above.

Dup 1-18 43 19 20 21 Number Street or Box Number 45 80

Dup 1-18 44 19 20 21 City 35 37 38 State 41 Zip 44 80

5. Compliance Status - The emissions from this source ___ can ___ cannot meet the emission limitations contained in the National Emission Standards on or prior to 90 days after the effective date of any standards or amendments which require the submission of such information.

Signature of Owner, Operator or Other Responsible Official

NOTE: If the emissions from the source will exceed those limits set by the National Emission Standards for Hazardous Air Pollutants, the source will be in violation and subject to Federal enforcement actions unless granted a waiver of compliance by the Administrator of the U.S. Environmental Protection Agency. The information needed for such waivers is listed in Section II of this form.

B. PROCESS INFORMATION. Part B should be completed separately for each point of emission for each hazardous pollutant. [Sources subject to 61.22(1) may omit number 4. below.]

Dup 1-13 14 16 00 17 18 5 19 20 SCC 27 28 29 NEDS-X Ref 30 IS 31 SIP

1. Pollutant Emitted - Indicate the type of hazardous pollutant emitted by the process. Indicate "AB" for asbestos, "BE" for beryllium, or "HG" for mercury.

32 33
Pollutant | 34 Regulation 48 | 49 EC

2. Process Description - Provide a brief description of each process (e.g., "hydrogen end box" in a mercury chlor-alkali plant, "grinding machine" in a beryllium machine shop). Use additional sheets if necessary.

50 Process Description 74 | 80

Dup 1-18 6 1
19 20 21 50
51 79 80

Dup 1-18 6 2
19 20 21 50
51 79 80

3. Amount of Pollutant - Indicate the average weight of the hazardous material named in Item 1 which enters the process in pounds per month (based on the previous twelve months of operation).

Dup 1-18 6 3
19 20 | 21 27 | lbs./mo. 29 36 | 80

4. Control Devices
a. Indicate the type of pollution control devices, if any, used to reduce the emissions from the process (e.g., venturi scrubber, baghouse, wet cyclone) and the estimated percent of the pollutant which the device removes from the process gas stream.

Dup 1-18 6 4 PRIMARY CONTROL DEVICE:
19 20 21 43

45 Primary Device Name 64 | 66 70 Percent Removal Efficiency | 72 79

80

Dup 1-18	6 5	SECONDARY CONTROL DEVICES:			
	19 20	21			45

				% EFFIC.	
47	Secondary Device Name	64	66 70 Percent Removal Efficiency	72 79	80

b. Asbestos Emission Control Devices Only

i. If a baghouse is specified in Item 4a, give the following information:

The air flow permeability in cubic feet per minute per square foot of fabric area.

Air flow permeability = _____ cfm/ft^2

The pressure drop in inches water gauge across the filter at which the baghouse is operated.

Operating pressure drop = _____ inches w.g.

If the baghouse material contains synthetic fill yarn, check whether this material is / / spun / / or not spun.

If the baghouse utilizes a felted fabric, give the minimum thickness in inches and the density in ounces per square yard.

Thickness = _____ inches Density = _____ oz/yd^2

ii. If a wet collection device is specified in Item 4a, give the designed unit contacting energy in inches water gauge.

Unit contacting energy = _____ inches w.g.

C. DISPOSAL OF ASBESTOS-CONTAINING WASTES. Part C should be completed separately for each asbestos-containing waste generation operation arising from sources subject to §61.22(a), (c), (e), and (h).

Dup 1-13			0 0-	5						
	14 16	17 18	19	20	SCC	27	28 29 NEDS X Ref	30 CS	31 SIP

A B				
32 33	34	Regulation	48	49
Pollutant				EC

1. Waste Generation - Provide a brief description of each process that generates asbestos-containing waste (e.g. disposal of control device wastes).

50 Process Description 79 80

2. Asbestos Concentration - Indicate the average percentage asbestos content of these materials.

Dup 1-18 6 1 19 20 21 ASBESTOS CONCENTRATION: 43 45 48

% 50 80

3. Amount of Wastes. - Indicate the average weight of asbestos-containing wastes disposed of, measured in kg/day.

Dup 1-18 6 2 19 20 21 27 29 kg/day 34 80

4. Control Methods - Indicate the emission control methods used in all stages of waste disposal, from collection, processing, and packaging to transporting and deposition.

Dup 1-18 6 3 19 20 21 Primary Control Method 43

45 79 80

Dup 1-18 6 4 19 20 21 50

51 79 80

5. Waste Disposal - Indicate the type of disposal site (sanitary landfill, open, covered) or incineration site (municipal, private) where the waste is disposed of and who operates the site (company, private, municipal). State the name and location of the site (closest city or town, county, state).

Dup 1-18 6 5 19 20 21 TYPE OF SITE: 33 35 50

51 79 80

Dup 1-18 6 6 (19 20) OPERATOR: (21 29) (31 50)

(51 79) (80)

Dup 1-18 6 7 (19 20) LOCATION: (21 29)

(31 70)

(71 79) (80)

D. WASTE DISPOSAL SITES. Part D should be completed separately for each asbestos waste disposal site subject to section 61.22(1).

Dup 1-13 (14 16) 0 0 (17 18) 5 (19 20) SCC (27) (28 29) HEDS X Ref (30) CS (31) SIP

A B
(32 33) Pollutant (34 Regulation 48) (49) EC

WASTE DISPOSAL SITE
(50 68) (80)

1. Description - Provide a brief description of the site, including its size and configuration, and the distance to the closest city or town, closest residence, and closest primary road.

Dup 1-18 6 1 (19 20) - SITE DESCRIPTION (21 37) (39 50)

(51 79) (80)

Dup 1-18 6 2 (19 20) DISTANCE: (21 29) TOWN: (30 34) (36 40) K M (42 43)

RESIDENCE: (45 54) (56 60) K M (62 63) ROAD: (65 69) (71 75)

K M
(77 78) (80)

2. Inactivation - After the site is inactivated, indicate the method or methods used to comply with the standard and send a list of the actions that will be undertaken to maintain the inactivated site.

Dup 1-18 6 8 19 20 21 COMPLIANCE METHOD/INACTIVE SITE: 52

54 79 80

II. WAIVER REQUESTS

A. WAIVER OF COMPLIANCE. Owners or operators of sources unable to operate in compliance with the National Emission Standards for Hazardous Air Pollutants prior to 90 days after the effective date of any standards or amendments which require the submission of such information may request a waiver of compliance from the Administrator of the U.S. Environmental Protection Agency for the time period necessary to install appropriate control devices or take modifications to achieve compliance. The Administrator may grant a waiver of compliance with the standard for a period not exceeding two years from the effective date of the hazardous pollutant standards, if he finds that such period is necessary for the installation of controls and that steps will be taken during the period of the waiver to assure that the health of persons will be protected from imminent endangerment.

The report information provided in Section I must accompany this application. Applications should be sent to the appropriate EPA regional office.

1. Processes Involved - Indicate the process or processes emitting hazardous pollutants to which emission controls are to be applied.

2. Controls

a. Describe the proposed type of control device to be added or modification to be made to the process to reduce the emissions of hazardous pollutants to an acceptable level. (Use additional sheets if necessary.)

b. Describe the measures that will be taken during the waiver period to assure that the health of persons will be protected from imminent endangerment. (Use additional sheets if necessary.)

3. Increments of Progress - Specify the dates by which the following increments of progress will be met.

Date by which contracts for emission control systems or process modifications will be awarded; or date by which orders will be issued for the purchase of the component parts to accomplish emission control or process modification.

Dup 1-16 017 17 19 53 54 55 60 61 MO/DY/YR 66 80

• Date of initiation of on-site construction or installation of emission control equipment or process change.

Dup 1-16 027 17 19 53 54 55 60 61 MO/DY/YR 66 80

• Date by which on-site construction or installation of emission control equipment or process modification is to be completed.

Dup 1-16 037 17 19 53 54 55 60 61 MO/DY/YR 66 80

• Date by which final compliance is to be achieved.

Dup 1-16 047 17 19 53 54 55 60 61 MO/DY/YR 66 80

B. WAIVER OF EMISSION TESTS. A waiver of emission testing may be granted to owners or operators of sources of beryllium or mercury pollutants if, in the judgment of the Administrator of the Environmental Protection Agency the emissions from the source comply with the appropriate standard or if the owners or operators of the source have requested a waiver of compliance or have been granted a waiver of compliance.

This application should accompany the report information provided in Section I.

1. Reason - State the reasons for requesting a waiver of emission testing. If the reason stated is that the emissions from the source are within the prescribed limits, documentation of this condition must be attached.

_____

_____

Date

Signature of the owner or operator

APPENDIX B—TEST METHODS

16. Method 105 is added to Appendix B as follows:

* * * * *

METHOD 105. METHOD FOR DETERMINATION OF MERCURY IN WASTEWATER TREATMENT PLANT SEWAGE SLUDGES

1. *Principle and applicability.* 1.1 Principle—A weighed portion of the sewage sludge sample is digested in aqua regia for 2 minutes at 95°C, followed by oxidation with potassium permanganate. Mercury in the digested sample is then measured by the conventional spectrophotometer cold vapor technique. An alternative digestion involving the use of an autoclave is described in paragraph 4.5.2 of this method.

1.2 Applicability—This method is applicable for the determination of total organic and inorganic mercury content in sewage sludges, soils, sediments, and bottom-type materials. The normal range of this method is 0.2 to 5 μg/g. The range may be extended above or below the normal range by increasing or decreasing sample size and through instrument and recorder control.

2. *Apparatus.* 2.1 Analysis—The conventional cold vapor technique(5) is used to analyze the sample.

2.1.1 Atomic Absorption Spectrophotometer[1]—Any atomic absorption unit having an open sample presentation area in which to mount the absorption cell is suitable. Instrument settings recommended by the particular manufacturer should be followed.

[1] Instruments designed specifically for the measurement of mercury using the cold vapor technique are commercially available and may be substituted for the atomic absorption spectrophotometer.

2.1.2 Mercury Hollow Cathode Lamp—Westinghouse WL-22847, argon filled, or equivalent.

2.1.3 Recorder—Any multirange, variable-speed recorder that is compatible with the UV detection system is suitable.

2.1.4 Absorption Cell—Standard spectrophotometer cells 10 cm long, having quartz end windows may be used. Suitable cells may be constructed from plexiglass tubing, 2.5 cm O.D. x 11.4 cm (ca. 1" O.D. x 4½"). The ends are ground perpendicular to the longitudinal axis, and quartz windows [2.5 cm diameter x 0.16 cm thickness (ca. 1" diameter x 1/16" thickness)] are cemented in place. Gas inlet and outlet ports [also of plexiglass but 0.6 cm O.D. (ca. ¼" O.D.)] are attached approximately 1.3 cm (½") from each end. The cell is strapped to a burner for support and aligned in the light beam to give the maximum transmittance. NOTE: Two 5.1 cm x 5.1 cm (ca. 2" x 2") cards with 2.5 cm (ca. 1") diameter holes may be placed over each end of the cell to assist in positioning the cell for maximum transmittance.

2.1.5 Air Pump—Any peristaltic pump capable of delivering 1 liter of air per minute may be used. A Masterflex pump with electronic speed control has been found to be satisfactory. (Regulated compressed air can be used in an open one-pass system.)

2.1.6 Flowmeter—Capable of measuring an air flow of 1 liter per minute.

2.1.7 Aeration Tubing—Tygon tubing is used for passage of the mercury vapor from the sample bottle to the absorption cell and return. Straight glass tubing terminating in a coarse porous frit is used for sparging air into the sample.

2.1.8 Drying Tube—15 cm long x 1.9 cm diameter (ca. 6" long x ¾" diameter) tube containing 20 grams of the desiccant magnesium perchlorate. The apparatus is assembled as shown in Figure 105-1. In place of the magnesium perchlorate drying tube, a small reading lamp with 60W bulb may be used to prevent condensation of moisture inside the cell. The lamp is positioned so as not to interfere with the measurement and to shine on the absorption cell maintaining the air temperature about 5°C above ambient.

3. *Reagents.* 3.1 Analysis.

3.1.1 Aqua Regia—Prepare immediately before use by carefully adding three volumes of concentrated HCl to one volume of concentrated HNO_3.

3.1.2 Sulfuric Acid, 0.5N—Dilute 14.0 ml of concentrated sulfuric acid to 1.0 liter.

3.1.3 Stannous Sulfate—Add 25 g stannous sulfate to 250 ml of 0.5N sulfuric acid. This mixture is a suspension and should be stirred continuously during use. Stannous chloride may be used in place of the stannous sulfate.

3.1.4 Sodium Chloride—Hydroxylamine Sulfate Solution—Dissolve 12 grams of sodium chloride and 12 grams of hydroxylamine sulfate in distilled water and dilute to 100 ml. Hydroxylamine hydrochloride may be used in place of the hydroxylamine sulfate.

3.1.5 Potassium Permanganate—5% solution, w/v. Dissolve 5 grams of potassium permanganate in 100 ml of distilled water.

3.1.6 Stock Mercury Solution—Dissolve 0.1354 grams of reagent grade mercuric chloride (Assay >95%) in 75 ml of distilled water. Add 10 ml of concentrated nitric acid and adjust the volume to 100.0 ml. 1 ml≃1 mg Hg.

3.1.7 Working Mercury Solution—Make successive dilutions of the stock mercury solution to obtain a working standard containing 0.1 μg per ml. This working standard and the dilutions of the stock mercury solution should be prepared fresh daily. Acidity of the working standard should be maintained at 0.15% nitric acid. This acid should be added to the flask as needed before the addition of the aliquot. Mercuric solutions should not be prepared in plastic containers.

4. *Procedures.* Samples for mercury analysis are subject to contamination from a variety of sources. Extreme care must be taken to prevent contamination. Certain interferences may occur during the analysis procedures. Extreme caution must be taken to avoid inhalation of mercury.

4.1 Sample Handling and Preservation.

4.1.1 Because of the extreme sensitivity of the analytical procedure and the omnipresence of mercury, care must be taken to avoid extraneous contamination. Sampling devices, sample containers, and reagents should be ascertained to be free of significant amounts of mercury; the sample should not be exposed to any condition in the laboratory that may result in contact or airborne mercury contamination. Sample containers to be used for collection and shipment of mercury samples should be properly cleaned before use. These should be rinsed with at least 20% v/v HNO_3 followed by distilled water.

4.1.2 While the sample may be analyzed without drying, it has been found to be more convenient to analyze a dry sample. Moisture may be driven off in a drying oven at a temperature of 60°C. No significant mercury losses have been observed by using this drying step. The dry sample should be pulverized and thoroughly mixed before the aliquot is weighed.

4.2 Interferences.

4.2.1 Interferences that may occur in sludge samples are sulfides, high copper, high chlorides, etc. A discussion of possible interferences and suggested preventative measures to be taken is given in Reference (6) (7).

4.2.2 Volatile materials which absorb at the 253.7 nm will cause a positive interfer-

ence. In order to remove any interfering volatile materials, the dead air space in the BOD bottle should be purged with nitrogen before the addition of stannous sulfate.

4.3 Handling Sample Mercury Vapors After Analysis.

4.3.1 Because of the toxic nature of mercury vapor, precaution must be taken to avoid its inhalation. Therefore, a bypass should be included in the analysis system to either vent the mercury vapor into an exhaust hood or pass the vapor through some absorbing media, such as:

(a) equal volumes of 0.1N $KMnO_4$ and 10% H_2SO_4;

(b) 0.25% iodine in a 3% KI solution.

A specially treated charcoal that will absorb mercury vapor is also available from Barnebey and Cheney, E. 8th Ave. and North Cassidy St., Columbus, Ohio 43219, Catalog No. 580–13 or No. 580–22.[3]

4.4 Calibration.

4.4.1 Transfer 0, 0.5, 1.0, 2.0, 5.0 and 10 ml aliquots of the working mercury solution containing 0 to 1.0 μg of mercury to a series of 300-ml BOD bottles. Add enough distilled water to each bottle to make a total volume of 10 ml: Add 5 ml of aqua regia and heat 2 minutes in a water bath at 95°C. Allow the sample to cool and add 50 ml distilled water and 15 ml of $KMnO_4$ solution to each bottle and return to the water bath for 30 minutes. Cool and add 6 ml of sodium chloride-hydroxylamine sulfate solution to reduce the excess permanganate. Add 50 ml of distilled water. Treating each bottle individually, add 5 ml of stannous sulfate solution and immediately attach the bottle to the aeration apparatus. At this point, the sample is allowed to stand quitely without manual agitation. The circulating pump, which has previously been adjusted to a rate of 1 liter per minute, is allowed to run continuously. The absorbance, as exhibited either on the spectrophotometer or the recorder, will increase and reach maximum within 30 seconds. As soon as the recorder pen levels off, approximately 1 minute, open the bypass valve and continue the aeration until the absorbance returns to its minimum value. Close the bypass valve, remove the fritted tubing from the BOD bottle and continue the aeration. Proceed with the standards and construct a standard curve by plotting peak height versus micrograms of mercury.

4.5 Analysis.

4.5.1 Weigh triplicate 0.2g±0.001 g portions of dry sample and place in bottom of a BOD bottle. Add 5 ml of distilled water and 5 ml of aqua regia. Heat 2 minutes in a water bath at 95°C. Cool and add 50 ml distilled water and 15 ml potassium permanganate solution to each sample bottle. Mix thoroughly and place in the water bath for 30 minutes at 95°C. Cool and add 6 ml of sodium chloride-hydroxylamine sulfate to reduce the excess permanganate. Add 55 ml of distilled water. Treating each bottle individually, add 5 ml of stannous sulfate and immediately attach the bottle to the aeration apparatus. With each sample, continue as described in paragraph 4.4.1 of this method.

4.5.2 An alternative digestion procedure using an autoclave may also be used. In this method 5 ml of concentrated H_2SO_4 and 2 ml of concentrated HNO_3 are added to the 0.2 grams of sample. 5 ml of saturated $KMnO_4$ solution are added and the bottle is covered with a piece of aluminum foil. The samples are autoclaved at 121°C and 2.1 kg/cm² (ca. 15 psig) for 15 minutes. Cool, make up to a volume of 100 ml with distilled water, and add 6 ml of sodium chloride-hydroxylamine sulfate solution to reduce the excess permanganate. Purge the dead air space and continue as described in paragraph 4.4.1 of this method.

5. *Calculation.* 5.1 Measure the peak height of the unknown from the chart and read the mercury value from the standard curve.

5.2 Calculate the mercury concentration in the sample by the formula:

$$\mu g\ Hg/gm = \frac{\mu g\ Hg \text{ in the aliquot}}{\text{wt. of the aliquot in g}}$$

5.3 Report mercury concentrations as follows: Below 0.1 μg/g; between 0.1 and 1 μg/g, to the nearest 0.01 μg/g; between 1 and 10 μg/g, to nearest 0.1 μg; above 10 μg/g, to nearest μg.

6. *Precision and accuracy.* 6.1 According to the provisional method in reference number 5, the following standard deviations on replicate sediment samples have been recorded at the indicated levels: 0.29 μg/g±0.02 and 0.82 μg/g±0.03. Recovery of mercury at these levels, added as methyl mercuric chloride, was 97 and 94%, respectively.

7. *References.*

1. Bishop, J. N. "Mercury in Sediments," Ontario Water Resources Comm., Toronto, Ontario, Canada, 1971.

2. Salma, M. Private communication, EPA Cal/Nev Basin Office, Alameda, California.

3. Hatch, W. R., and Ott, W. L. "Determination of Sub-Microgram Quantities of Mercury by Atomic Absorption Spectrophotometry," Ana. Chem. *40*, 2085 (1968).

4. Bradenberger, H. and Bader, H. "The Determination of Nanogram Levels of Mercury in Solution by a Flameless Atomic Absorption Technique," Atomic Absorption Newsletter *6*, 101 (1967).

5. Analytical Quality Control Laboratory (AQCL), Environmental Protection Agency, Cincinnati, Ohio, "Mercury in Sediment (Cold Vapor Technique)," Provisional Method, April 1972.

6. Kopp, J. F., Longbottom, M. C. and Lobring, L. B. "Cold Vapor Method for Determining Mercury," Journal AWWA, 64, 1 (1972), pp. 20–25.

7. "Manual of Methods for Chemical Analysis of Water and Wastes," Environmental Protection Agency, EPA–625/2–74–003, pp. 118–138.

[FR Doc.75-27231 Filed 10-14-75;8:45 am]

[3] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

3

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 61

[AH-FRL 2324-3]

National Emission Standards for Hazardous Air Pollutants; Standards for Radionuclides

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Rule and Announcement of Public Hearing.

SUMMARY: On November 8, 1979, EPA listed radionuclides as a hazardous air pollutant under the provisions of Section 112 of the Clean Air Act. Pursuant to Section 112, EPA is proposing standards (including appropriate reporting requirements) for sources of emissions of radionuclides in four categories: (1) Department of Energy (DOE) Facilities, (2) Nuclear Regulatory Commission licensed facilities and non-DOE Federal facilities, (3) underground uranium mines, and (4) elemental phosphorous plants.

The Environmental Protection Agency (EPA) has identified several additional source categories that emit radionuclides and has determined there are good reasons for not proposing standards at this time for these categories. They are the following: (1) coal-fired boilers, (2) the phosphate industry, (3) other extraction industries, (4) uranium fuel cycle facilities, uranium mill tailings, management of high level waste, and (5) low energy accelerators.

DATES: Comments may be received on or before May 30, 1983.

Public Hearings. An informal public hearing will be held on April 28, 29, and 30, 1983 in Washington, D.C. The exact time and location of the hearing can be obtained by calling the Office of Radiation Programs at (703) 557-0704. Requests to participate in the informal hearing should be made by April 20, 1983. Written statements may be entered into the record before, during, or within 30 days after the hearing.

ADDRESSES: All written comments should be submitted to the Central Docket Section (A-130), U.S. Environmental Protection Agency, Washington, D.C. 20460, Attention: Docket No. A-79-11. This docket, containing information used by EPA in developing the proposed standards, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday at EPA's Central Docket Section, West Tower Lobby, Gallery One, Waterside Mall, 401 M Street SW., Washington, D.C. 20460.

Separate sections of the docket have been established for each category of radionuclide emissions to air. Comments specific to a proposed action should be addressed to the following docket sections:

Section III A—Department of Energy Facilities
Section III B—Nuclear Regulatory Commission Licensed Facilities and non-DOE Federal Facilities
Section III C—Underground Uranium Mines
Section III D—Elemental Phosphorous Plants
Section III E—Coal-fired Boilers
Section III F—Phosphate Industry
Section III G—Other Extraction Industries
Section III H—Uranium Fuel Cycle Facilites, Uranium Mill Tailings, and Management of High Level Waste
Section III I—Low Energy Accelerators

Requests to participate in the informal hearing should be made in writing to Richard J. Guimond, Director, Criteria and Standards Division (ANR-460), U.S. Environmental Protection Agency, Washington, D.C. 20460. All requests for participation should include, at least, an outline of the topics to be addressed in the opening statements and the names of the participants. Presentations should be limited to 15 minutes each.

A Background Information Document has been prepared that contains, for each source category, projected doses and risks to nearby individuals and to populations, descriptions of current control technology, and descriptions and costs of emission control technologies. Single copies of the Background Information Document for the proposed standards may be requested in writing from the Program Management Office (ANR-458), U.S. Environmental Protection Agency, Washington, D.C. 10460, or by calling (703) 557-9351.

FOR FURTHER INFORMATION CONTACT: Terrence A. McLaughlin, Chief, Environmental Standards Branch (ANR-460), U.S. Environmental Protection Agency, Washington, D.C. 20460, (703) 557-8977.

SUPPLEMENTARY INFORMATION:

I. Overview of the Proposed Standards

A. Basic Terms Used in This Notice

All matter is made up of atoms; their nuclei contain protons and neutrons. The number of protons in an atom determines the identity of the element. For example, the element with 6 protons is called carbon. Atoms can contain different numbers of neutrons. The total number of protons and neutrons in an atom is called the atomic weight.

The nuclei of atoms of chemical elements with certain atomic weights are unstable by nature. Such nuclei can disintegrate spontaneously in predictable ways and are said to be radioactive. Atoms with nuclei that disintegrate are called radionuclides. For example, carbon atoms with 8 neutrons disintegrate, whereas carbon atoms with 6 neutrons are stable. The number of disintegrations which will occur in a given amount of time is termed activity; the unit of activity is the curie. One curie equals 37,000,000,000 disintegrations per second.

Some radionuclides are found in nature; others are made in reactors and accelerators. This notice concerns facilities which handle or produce all types of naturally occurring and manmade radionuclides in a manner that results in their being released into the air.

B. Background

In 1977, Congress amended the Clean Air Act (the Act) to address airborne emissions of radioactive materials. Before 1977, these emissions had been either regulated under the Atomic Energy Act or unregulated. Section 122 of the Act required the Administrator of EPA, after providing public notice and opportunity for public hearings (provided by 44 FR 21704, April 11, 1979), to determine whether emissions of radioactive pollutants cause or contribute to air pollution that may reasonably be anticipated to endanger public health. On December 27, 1979, EPA published a **Federal Register** Notice listing radionuclides as hazardous air pollutants under Section 112 of the Act (44 FR 76738, December 27, 1979). To support this determination, EPA published the report titled *Radiological Impact Caused By Emissions of Radionuclides into Air in the United States—Preliminary Report* [EPA 520/7-79-006], Office of Radiation Programs, U.S. Environmental Protection Agency, Washington, D.C. (August 1979).

Section 122(c)(2) of the Act directed that, once EPA listed radionuclides to be regulated under the Act, EPA and the Nuclear Regulatory Commission (NRC) were to enter into an interagency agreement with respect to those facilities under NRC jurisdiction. Such a memorandum of understanding was effected on October 24, 1980, and was subsequently published in the **Federal Register** (45 FR 72980, November 3, 1980). When EPA began developing standards for Department of Energy (DOE) facilities, a similar memorandum of understanding was negotiated with DOE. This memorandum of understanding was signed in October 1982, and a copy has been placed in the Docket for public review.

On June 16, 1981, the Sierra Club filed suit in the U.S. District Court for the Northern District of California pursuant to the citizens' suit provision of the Act (Sierra Club v. Gorsuch, No. 81–2436 WTS). The suit alleged that EPA had a nondiscretionary duty to propose standards for radionuclides under Section 112 of the Act within 180 days after listing them. In March 1982, the Court granted the Sierra Club motion for partial summary judgment on the liability issue, and, on September 30, 1982, the Court ordered EPA to publish proposed regulations establishing emission standards for radionuclides, with a notice of hearing, within 180 days of the date of that order.

EPA is proposing standards for certain sources of radionuclide emissions to air and is proposing not to regulate other sources. To EPA's knowledge, these comprise all source categories that release potentially regulatable amounts of radionuclides to air. The deadline established by the Court for this rulmaking has required EPA to proceed with less information than it would like. As always, EPA invites comments and will consider them carefully to ensure that the Agency's decisions are the best possible ones.

C. Estimates of Health Risk

Agencies can never obtain perfect data but have to make regulatory decisions on the basis of the best information available. Although additional study may be suggested to clarify the health implications from exposure to radiation at relatively low levels, EPA is concerned about the potential detrimental effects to human health caused by radiation based on the best scientific information currently available. EPA believes its estimates of doses to humans and the potential human health risks constitute an adequate basis for decisionmaking.

The information used by the Agency in estimating the hazards to health due to exposure to radiation is summarized in the following reports: *The Effects on Populations of Exposure to Low Levels of Ionizing Radiation* (1972) and *Health Effects of Alpha Emitting Particles in the Respiratory Tract* (1976) by the BEIR Committee, the report of the United Nations Scientific Committee on the Effects of Atomic Radiation entitled *Sources and Effects of Ionizing Radiation* (1977), and *Publication 26* (1977) by the International Commission on Radiological Protection. These bodies agree that high levels of radiation cause cancer and mutations and that, when formulating radiation protection standards and guidance, it is reasonable to assume that the risks of cancer and mutations are proportional to radiation dose. Background information on the risk associated with radon emissions can be found in an EPA report titled *Indoor Radiation Exposure Due to Radium–226 in Florida Phosphate Lands*, [EPA 520/4–78–013] (1978).

In concert with the recommendations of these reports, even for relatively low doses, EPA has assumed a linear, nonthreshold, dose-effect relationship as a reasonable basis for estimating the public health hazards due to exposure to radiation. This means that any radiation dose is assumed to pose some risk of damage to health and that the risk associated with low doses is directly proportional to the risk that has been demonstrated at higher doses. EPA believes this assumption is reasonable for public health protection in light of presently available information. However, EPA recognizes that the data available preclude neither a threshold for some types of damage below which there are no harmful effects nor the possibility that low doses of gamma radiation may be less harmful to people than the linear model implies.

As used in this notice, the term "dose to an individual" means an estimate of the dose rate in units of dose equivalent per year (rem/y) to the whole body or to a specified body organ due to exposure to radiation at a given level for the person's lifetime (70 years). These dose rates are a measure of, although not directly proportional to, the individual's risk of fatal cancer. The term "lifetime risk to an individual" means an estimate of the potential probability of premature death due to cancer caused by radiation exposure at a given level for the person's lifetime. There are also risks of nonfatal cancer and serious genetic effects, depending on which organs receive the exposure to radiation. The risks of nonfatal cancer and genetic effects cannot be accurately estimated, but neither risk is larger than the fatal cancer risk. EPA considers all these risks when it makes regulatory decisions on limiting emissions by restricting dose rates or exposures to radionuclide concentrations.

As used in this notice, the term "dose to population" means an estimate of the summed dose received by all persons in a population living within a given distance of the source, typically within 80 kilometers, due to a one year release of radionuclides (person-rem per year of operations). A person-rem is a total amount of exposure received by a large group equivalent to one person receiving an exposure of one rem. The term "risk to population" means an estimate of the number of potential fatal cancers that might occur in the population living within a given distance of the emission source, typically within 80 kilometers. The risk is related to the amount of radionuclides that are emitted during a year of operation. Part of the population risk is likely to occur some time after the radionuclides are emitted because: (1) There is a delay between release and exposure as the radionuclides move through environmental pathways and (2) there is a latent period between exposure and the onset of the disease. The dose to populations for a specific organ is related to, although not directly proportional to, the risks of fatal cancer, nonfatal cancer, and serious genetic effects. EPA considers all fatal and nonfatal risks in making regulatory decisions on whether standards are needed to protect the general public. As used in this notice, the term "health effect" means potential fatal cancers. Additional information on risk can be found in the Draft Background Information Document.

EPA must make numerous assumptions when estimating the radiation dose to individuals and population groups and the likely risk this might present to health. The assumptions introduce uncertainties in the estimates of radiation doses and health risks. All individual risk calculations assume that individuals reside at a single location for a 70 year life and are exposed to a constant source of radionuclide emissions for the entire time. factors such as radionuclide uptake by vegetation, consumption of locally produced crops and milk, and meteorology are quite site specific and can influence the actual risk to any given individual. Individual characteristics such as age, physiology, physical activity level, amount of time spent indoors, and eating habits can influence the rate and amount of radionuclides affecting the individual and, thus, the risk of that person.

EPA's risk estimates are "best estimates" considering the above factors. EPA believes that the estimates are within a factor of ten of the actual health risks to individuals if the assumptions are valid for the particular situation under consideration.

D. Summary of the Proposed Standards

EPA is proposing specific standards for sources in four categories: (1) DOE facilities, (2) NRC-licensed facilities and non-DOE Federal facilities, (3) underground uranium mines and (4) elemental phosphorous plants.

An indirect emission standard is proposed for all DOE facilities that will restrict emissions from each site to the

amount that would cause an annual dose equivalent to 10 millirem (mrem) to the whole body and 30 mrem to any organ of any individual. This emission standard will keep the radiation doses relatively low both to nearby individuals and to populations living around the sites. In addition, EPA expects these facilities to continue to comply with the current Federal Guidance requirement that emissions be limited to as low as practicable levels and has proposed a reporting requirement to describe emission control technology.

An indirect emission standard is proposed for NRC licensees and non-DOE Federal facilities that will restrict emissions from each site to the amount that would cause an annual dose equivalent of 10 mrem to any organ of any individual. This emission standard will keep radiation doses relatively low to nearby individuals and populations in the vicinity of the site. The term "NRC licensees" includes those facilities licensed by the NRC and by States under agreement with the NRC.

An indirect emission standard is proposed for underground uranium mines that will restrict the increase in annual average concentration of radon-222 at places people can live to 0.2 picocurie per liter (pCi/1). A person living in a house for a long time in an area exposed to this concentration might still be subject to a significant estimated level of risk. However, neither control technology nor other methods to reduce radon emissions from these mines are available at reasonable cost; thus, more restrictive controls are not reasonable. The proposed standard will reduce risk to people living closest to the mines; protection of the health of regional and more distant populations is of less concern because most mines are located in remote areas.

An emission standard is proposed for elemental phosphorous plants that will limit annual emissions of polonium-210 from each site to 1 curie. While other radionuclides are emitted from these plants, polonium-210 is the major contributor to the maximum individual risk. Limiting polonium-210 will control the others. Such a standard will keep radiation doses relatively low to both individuals and populations.

While one of the above standards limits stack emissions directly, the other three limit stack emissions indirectly by specifying dose or concentration limits to be achieved. EPA believes this is a reasonable approach, given the extreme diversity of DOE facilities and NRC licensees and the fact that randon-222 emissions from uranium mines are not amenable to controls. The form of the proposed standards follows well developed and widely accepted practices in radiation protection. The use of procedures developed primarily to control chemicals would, in this context, be unworkable.

E. Basis for the Proposed Standards

In the Federal Register of May 18, 1960, President Eisenhower directed Federal agencies to follow the Radiation Protection Guidance of the Federal Radiation Council (FRC). When EPA was established, the Federal Radiation Council was abolished, and its responsibilities were transferred to EPA. EPA has considered this Guidance in establishing emission standards under Section 112 of the Clean Air Act, and the Agency's approach is compatible with it. For the purposes of this rulemaking, key elements of the Guidance are:

1. There should not be any man-made radiation exposure without the expectation of benefit resulting from such exposure.

2. The term "Radiation Protection Guide" should be adopted for Federal use. This term is defined as the radiation dose which should not be exceeded without careful consideration of the reasons for doing so; every effort should be made to encourage the maintenance of radiation doses as far below this guide as practicable.

3. For the individual in the population, the basic Radiation Protection Guide for annual whole body dose in 0.5 rem. This Guide applies when the individual whole body doses are known. As an operational technique, where the individual whole body doses are not known, a suitable sample of the exposed population should be developed whose Protection Guide for annual whole body dose will be 0.17 rem per capita per year.

4. There can be no single permissible or acceptable level of exposure without regard to the reason for permitting the exposure. It should be general practice to reduce exposure to radiation, and positive efforts should be carried out to fulfill the sense of these recommendations. It is basic that exposure to radiation should result from a real determination of its necessity.

5. There can be different Radiation Protection Guides with different numerical values, depending upon the circumstances.

6. The Federal agencies shall apply these Radiation Protection Guides with judgment and discretion to assure that reasonable probability is achieved in the attainment of the desired goal of protecting man from the undesirable effects of radiation. The Radiation Protection Guides provide a general framework for the radiation protection requirements. It is expected that each Federal agency, by virtue of its immediate knowledge of its operating problems, will use these Guides as a basis upon which to develop detailed standards tailored to meet its particular requirements.

EPA believes that the following points in these guides are of particular importance: (1) There should be benefits from exposure to radiation; (2) Exposures should be kept as low as practicable; and (3) It is appropriate to have different standards with different values, depending on the circumstances.

These Guides apply to Federal agencies to the extent that they are not imcompatible with more specific legislative directives. The Clean Air Act directs EPA to establish emission standards for hazardous pollutants and directs EPA to propose these standards at a level which, in the Administrator's judgment, will protect the public health with an ample margin of safety. Congress did not describe the degree of protection that provides an ample margin of safety, nor did it describe what factors the Administrator should consider in making these judgments. Therefore, EPA considers those factors it believes are necessary to make reasonable judgments on whether standards are needed and, if so, at what level they should be established.

If a hazardous pollutant under review has been shown to possess a threshold level below which no deterimental health effects are likely, it might be relatively easy to establish an emission standard. For example, the Agency might select an appropriate safety factor, divide the threshold level by this factor, and establish an emission standard that corresponds to the reduced level. This regulatory strategy would provide reasonable assurance that no detrimental effects would result from exposure to the hazardous pollutant.

This approach is not feasible or reasonable for radionuclides. This is because the risk of cancer from exposure to radiation has not been shown to have a threshold level. Consequently, if EPA applied the approach previously described, the Agency would likely conclude that the standard should be established at zero emissions. They only way to meet such a standard would be to close all facilities emitting radionuclides because it is impossible to reduce radionuclide emissions to zero through control technology. If this approach were adopted, society would be harmed greatly since it would have to forgo the

benefits of industries that emit radionuclides. Therefore, to allow society to continue to benefit from these activities, EPA must establish emission standards for radionuclides at a level that may present some human health risk. The Agency is not aware of any single level of risk that would be generally acceptable or consititute an ample margin of health protection. Some argue that an increase in cancer risk not exceeding one in 1000 due to a specific cause is acceptable, whereas others argue that an increase in risk of one in one million is unacceptable. EPA believes it should adopt an approach that will allow those various factors that influence society's health and well being to be weighed in assessing each source category. To accomplish this, EPA has decided to consider the following factors in making its judgments:

1. The radiation dose and risk to nearby individuals;
2. The cumulative radiation dose and risk to populations in the vicinity of the source;
3. The potential for radiation emissions and risk to increase in the future;
4. The availability, practicality, and cost of control technology to reduce emissions; and
5. The effect of current standards under the Act or other applicable legislative authorities.

By considering these factors, EPA will be able to provide public health protection that is consistent with the intent of the Federal Radiation Protection Guides and Clean Air Act.

The first three factors are used to assess the likely impact of emissions on the health of individuals and large populations and to estimate the potential for significant emissions in the future. The fourth factor enables EPA to assess whether state-of-the-art control technologies are currently in use and whether there are any practical means of reducing emissions through control technology or other control strategies. The last factor allows EPA to assess whether regulations or standards that have been established to control particulates or other pollutants are also minimizing releases of radionuclides.

The dose and risk to the individuals nearest a site are often the primary considerations when evaluating the need to control emissions of radionuclides. Controlling maximum individual dose assures that people living nearest a source are not subjected to unreasonably high risk. Further, protecting individuals usually provides an adequate level of protection to populations living further away from the source. Estimating the maximum individual dose and risk allows a comparison of the potential impact of one source to other sources.

EPA believes that cumulative population dose and risk also need to be examined. The cumulative radiation dose and risk to surrounding populations are determined by adding together all of the individual doses and risks that everyone within a certain radius (usually 80 km) of an emission source receives. This factor can sometimes be more important than the maximum individual risk in deciding whether controls are needed, particularly if an extremely large population may be exposed. The aggregate dose and population risk can be of such magnitude that it would be reasonable to require a reduction in the total risk even though, if the maximum individual dose were considered alone, one might conclude that no further controls are needed.

In addition, EPA believes that the potential for emissions and risk to increase in the future needs to be considered even though the current projected maximum individual and population risks are very low. An emission standard might be appropriate because the facilities now, or may in the future, handle large quantities of radionuclides that could escape into the air if improperly controlled. Alternatively, when the amount handled by a facility is small or is decreasing, and there is no potential for large releases now or in the future, standards may not be needed.

The availability and practicality of control technology are important in judging how much control of emissions is warranted. For this rulemaking, EPA believes that the standard should be established at a level that will require best available technology with allowance for variation in emissions, once a determination is made that additional controls are necessary. Additional actions, such as requiring development of new technology, closure of a facility, or other extreme measures may be considered if significant emissions remain after best available technology is in place or if there are significant emissions and there is no applicable control technology. EPA is defining best available technology as that which, in the judgment of the Administrator, is the most advanced level of controls adequately demonstrated, considering economic, energy, and environmental impacts. The technological and economic impacts associated with retrofits are considered when determining best available technology for existing sources.

Finally, EPA believes it is reasonable to consider whether other EPA standards are achieving approximately the same goal as the Act, i.e., protecting public health with an ample margin of safety. In cases where other standards are providing comparable control for radionuclides, EPA believes it is appropriate not to propose redundant standards under the Act. There would be no benefits because the public health would already be protected with an ample margin of safety, but there could be unnecessary costs associated with implementing an additional standard.

EPA considered each of the relevant factors in making determinations for each source category that was reviewed. These factors were not quantitatively balanced through the use of formulas to derive emission limits. Rather, they were qualitatively weighed before deciding whether a standard was needed and, if so, what level of control was suitable. The consideration of these factors as they apply to each source category is detailed in the portion of this preamble devoted to that source category.

EPA requests comments on the appropriateness of the factors it has selected for consideration. Should some factors be added or deleted? Should more emphasis be placed on some factors than others? How should the cost-effectiveness, cost-benefits, or affordability of controls be considered when establishing appropriate emission standards to provide an ample margin of safety? EPA also requests comments on whether the factors were appropriately applied to the nine source categories that were reviewed.

It is the intent of the Act that control technology or operational practices be used to control emissions. Buying land to expand the size of the site or building higher stacks to reduce exposure to nearby individuals may not be used where other emission control devices or operational procedures are reasonably available. However, there are radionuclides, principally radon, which present significant risks and for which emission controls may not always be reasonably available. As a last resort in such cases, EPA has decided to propose standards achievable through dispersion techniques.

II. Department of Energy Facilities (DOE)

A. General Description

DOE administers many facilities that emit radionuclides to air. These facilities are Government owned but are managed and operated for DOE by private contractors. Operations at these

facilities include research and development, production and testing of nuclear weapons, enrichment of uranium and production of plutonium and other fissile materials for nuclear weapons, reactors, and other purposes, and processing, storing, and disposing of radioactive wastes. These facilities are on large sites, some of which cover hundreds of square miles in mostly remote locations, and are located in about 20 different states. Some of the smaller facilities resemble typical industrial sites and are located in suburban areas.

Each facility differs in emission rates, site size, nearby population densities, and other parameters that directly affect the dose from radionuclide emissions. Many different kinds of radionuclides are emitted to air. Six sites have multipurpose operations spread over very large areas. About a dozen sites are primarily research and development facilities, located in more populated areas. Reactor and accelerator operations at these sites may release radioactive noble gases and tritium; other operations may release small amounts of other radionuclides. Several facilities are primarily engaged in weapons development and production and may release small amounts of tritium and cretain long-lived radionuclides. Finally, two sites are dedicated entirely to gaseous diffusion plants that enrich uranium for use in utility electric power reactors and for defense purposes. They primarily emit uranium.

B. Estimates of Dose and Risk

At 15 of the 25 DOE facilities, which are considered as a group in the Background Information Document because of their relatively small health impact, the doses to the nearby individuals ar estimated to be considerably less than 1 millirem per year (mrem/y). The collective dose to the populations living around the sites is also low, no higher than about 10 person-rem as the result of 1 year of site operation. The health risk associated with this group is correspondingly low. The maximum lifetime risk to the most exposed individual is estimated to be less than 10 in 1,000,000 and the impact on the population is estimated to be less than 1 potential health effect per 100 years of operation. These estimates were developed using methods and assumptions discussed in Unit I.C. of this notice.

A second group of 13 facilities, those with the largest emissions of radionuclides, were studied in more detail. They included the following major sites: Argonne National Laboratory, Brookhaven National Laboratory, Feed Materials Production Center, Fermi National Accelerator Laboratory, Hanford Reservation, Idaho National Engineering Laboratory, Lawrence Livermore Laboratory, Los Alamos National Laboratory, Oak Ridge Reservation, Paducah Gaseous Diffusion Plant, Portsmouth Gaseous Diffusion Plant, Rocky Flats Plant, and the Savannah River Plant.

The highest doses to individuals are projected for Los Alamos national Laboratory (about 9 mrem/y to all organs), Oak Ridge Reservation (about 50 mrem/y to lung and 8 mrem/y to the bone) the Paducah Gaseous Diffusion Plant (about 7 mrem/y to bone and 5 mrem/y to the lung), the Portsmouth Gaseous Diffusion Plant (about 11 mrem/y to bone, 7 mrem/y to lung and 2 mrem/y to thyroid), Feed Materials Production Center (about 88 mrem/y to lung and 26 mrem/y to bone), and Savannah River Plant (about 2 mrem/y to most organs and 5 mrem/y to the thyroid). The corresponding doses to large populations ranged up to about 200 person-rem to the lung per year of site operations. The corresponding maximum lifetime risk to the most exposed individual is estimated to be less than about 2 in 10,000, while the total risk to populations surrounding all 13 sites is estimated to be less than 1 potential health effect per 15 years of operation.

All risk estimates for DOE facilities were developed using methods and assumption discussed in Unit I.C. of this notice. It is important to recognize that the actual risk to specific individuals may differ greatly from these estimates because the circumstances involving the actual exposure may differ significantly from the assumptions used to make the estimates.

C. Emission Control Technology

Emissions from DOE facilities are, in general well controlled as part of a long-standing DOE program of systematically upgrading emission controls when practical. High-efficiency filters, usually in series when large amounts of radionuclides are processed, are used to control particulate emissions. At some facilities, there are processes that discharge radioactive noble gases and tritium mixed with large volumes of air. For these cases, control technologies to remove the boble gases and tritium are usually not feasible.

At the Oak Ridge site, the highest doses to nearby individuals are mostly caused by uranium-234 and uranium-238 emissions from the Y-12 plant, a facility that has fabrication operations using enriched uranium. Particulate emissions from this facility are controlled by scrubbers, prefilters, cloth bag filters, or high-efficiency particulate filters. At the Feed Materials Production Center, the highest projected doses to nearby individuals are due to emissions of uranium-234 and uranium-238 from fabrication operations using uranium. There is also high exposure to radon decay products due to wastes containing radium-226 that are stored on this site. Particulate emissions are controlled by cloth bag filters or scrubbers but can be reduced further by additional high-efficiency filters or improved scrubbers. Waste tanks can be sealed to prevent the escape of radon.

D. The Proposed Standard

EPA is proposing that emissions of radionuclides from DOE facilities be restricted to the amount that would cause a dose equivalent rate of 10 mrem/y to the whole body and 30 mrem/y to any organ of any individual living nearby. For most practical purposes, compliance with this standard would be determined by calculating the doese to persons assumed to be living at the site boundary.

Consistent with the principles embodied in Federal Radiation Guidance to keep exposure to radiation as low as practical, it is EPA's intent that facilities subject to the DOE standard shall use best available technology even if compliance is possible with a lesser degree of control. This means that operators should periodically evaluate radionuclide emissions to air and reduce them to as low a level below the standard as is reasonably possible. This also means that the facilities now well controlled to levels considerably below the proposed standard should not relax their emission controls and that new facilities should use best available emission controls.

To determine if the standard is being implemented in a manner that keeps exposure as low as practicable, EPA is proposing a reporting requirement. DOE shall submit to EPA a concise annual report which includes the results of monitoring emissions, dose calculations, and discussions of DOE's programs for maintaining airborne releases of radionuclides as low as practicable. Much of this information is currently being collected; for example, emission data are reported by DOE's effluent information systems and annual site reports describe recent and planned improvements in emission controls. Therefore, EPA believes the burden of this reporting is reasonable. This information will be reviewed by EPA in

carrying out its compliance responsibilities.

The proposed emission standards of 10 mrem/y whole body and 30 mrem/y to any organ were selected by considering highest existing emissions from those major DOE facilities where best available technology is used and considering the level to which emissions would be reduced by applying additional controls to other facilities. Uniform standards for DOE facilities could not be set lower than these values because emissions from some major DOE facilities cannot, as a practical matter, be reduced further without closing major operations at the facilities. These DOE facilities provide substantial benefits in the areas of electrical power generation and national defense. The consequence of a more restrictive standard would be to eliminate some of these beneficial activities. Consequently, the risks associated with the proposed standard are not unreasonable. Those few DOE facilities, tending to have emissions greater than this proposed limit can, in EPA's judgment, reduce their emissions using available technology or work practices. EPA believes that the proposed standard would be met if the following plants upgraded their control technology: (1) Oak Ridge Y-12 plant ($10 million capital costs) (2) Feed Materials Production Center ($15 million capital costs).

The dose allowed by the proposed standard is a factor of 50 lower than the current upper limits now used by DOE. These current upper limits are based on the 1960 recommendations of the Federal Radiation Council, although the Federal Radiation Council admonished Federal agencies to establish standards that would reduce emissions to as low as practical below the upper limits. Actual public exposure to radiation due to releases from DOE facilities has been far below the 1960 Federal Guidance levels because of the DOE practice of limiting emissions to as low as practicable levels. Since the proposed standard is much more restrictive than the 1960 guidance, it will limit radiation doses to low levels. In practice, EPA expects that most DOE facilities will operate well below the proposed standard.

EPA estimates the actual lifetime individual risk associated with the proposed standard to be at the most about 2 in 50,000 when facilities are complying with the standard. EPA believes that the proposed standard and the reporting requirement will protect the public living around DOE facilities with an ample margin of safety. The uncertainty associated with estimates of radiation does and risk is discussed in Unit I.C. and II.B of this notice.

EPA requests comments on the proposed values and the methodology used in arriving at them.

E. Alternatives to the Proposed Standard

EPA considered proposing emission limits in units of curies per year (Ci/y) for each radionuclide, with secondary corrections for particle size, lung clearance class, and other such factors. This approach was rejected because it would require very detailed and complex emission limits for each DOE facility to be as protective of public health as the proposed standard. In EPA's judgment, this would be so complex and difficult as to be infeasible.

The Agency considered proposing higher values than the proposed dose limit. We believe that many of these facilities are achieving the proposed standard at current operating levels. For the few cases where additional controls are needed to meet the standard, the technology appears available and effective and is not unreasonably expensive to purchase or operate. The protection offered by the proposed standard appears achievable, and we have not identified any good reason for accepting a lesser degree of protection.

Lower values were considered. Such limits, would be extremely costly or could force the closure of major operations of benefit to the country, possibly at several sites. The possible small additional reduction of dose and risk to a few individuals is not sufficient to justify such severe action.

Emission limits that would control dose to the general population rather than individuals were considered. In particular, EPA considered emission limits for long-half-life radionuclides such as tritium, carbon-14, krypton-85, and iodine-129. These kinds of radionuclides may cause population doses that are more significant than the doses these radionuclides cause to nearby individuals. EPA decided not to propose this kind of standard. For DOE facilities, population doses from these radionuclides are small; the highest of these small doses are caused by emissions of tritium for which control technologies are not effective. Consequently, proposing emission standards for long-half-life radionuclides at existing DOE facilities would not serve a useful purpose.

Different emission limits were considered for existing and new DOE facilities and for specific groups of DOE facilities, rather than setting uniform standards for all DOE facilities. Such a strategy would permit more restrictive standards for certain DOE facilities, although not for all of them, at the cost of having to develop a much more complex standard. Rather than do this, EPA will rely on existing Federal Guidance to all Federal agencies to ensure that exposures are kept as far below the proposed standard as practicable and has added a reporting requirement to this end. This should provide, in practice, the same measure of emission control. EPA requests comments on the desirability of setting separate standards for different categories of DOE facilities.

EPA considered the alternative of proposing the standard in the form of a risk-equivalent, whole-body dose, using methodology similar to that recently recommended by the International Commission on Radiation Protection. The principal advantage is one of equity; that is, the emissions from each facility are limited on the basis of causing equivalent levels of risk. A disadvantage of this alternative is that the proposed standard would have to be reduced from 10 mrem/y to about 5 mrem/y to maintain a comparable degree of protection with the 30 mrem/y limit to any organ. Some sources could not meet such a standard using currently available technology. The Agency particularly requests comment on the use of the whole-body, risk-equivalent dose method as an approach to selecting emission standards.

EPA considered requiring the proposed standard to be met at a site boundary in all cases, even if there are good reasons why people are not likely to be at that location, but decided not to because this would be unrealistic. EPA requests comments on where the standard should apply.

F. Implementation of the Proposed Standards

The standards will be implemented by DOE pursuant to the Memorandum of Understanding between EPA and DOE. EPA will provide oversight to ensure that implementation procedures are appropriate. The standard should be implemented using pathway and dose calculations based on EPA's codes or, alternatively, on modeling techniques which, in EPA's judgment, are as suitable for particular applications as the EPA codes.

II. NRC Licensed Facilities and Non-DOE Federal Facilities

A. General Description

This category of facilities encompasses a wide range of activities

including research and test reactors, shipyards, the radiopharmaceutical industry, and other industrial facilities. For purposes of this proposed rule, EPA excludes facilities that are part of the uranium fuel cycle. The category includes both facilities licensed by NRC and facilities licensed by a State under an agreement with NRC. These facilities number in the tens of thousands and are located in all 50 states. The principal differences among these various types of activities are their emission characteristics and rates, their sizes, and the population densities of the surrounding areas. The following discussion provides illustrative examples.

There are a wide variety of designs of research and test reactors, and they operate over a range of power levels from near zero to approximately 10 megawatts. They emit primarily argon–41 and tritium at rates ranging from less than 1 Ci/y of each radionuclide up to several thousand Ci/y of argon–41 and several hundred Ci/y of tritium. They are most often located at or near universities.

The radiopharmaceutical industry currently produces about 65 different radionculides for a variety of uses in hospitals and clinics. In most cases, emissions of iodine–125 and iodine–131 cause the highest organ (thyroid) doses to nearby individuals because: (1) They are emitted in the largest quantities, (2) environmental pathways bring them into contact with man, and (3) the thyroid concentrates iodine. Emissions occur at radiopharmaceutical manufacturing sites, hospitals, and sewage treatment plants receiving hospital wastewater.

There are many other industrial uses of a number of different radionuclides that result in emissions to air, including the manufacture of industrial gauges, static eliminators, radiographic devices, and certain commercial products (e.g., self-illuminating watches and smoke detectors). Most of the industrial uses of radionuclides involve production of sealed (encapsulated) sources. Once their manufacture is completed, these sealed sources do not emit radionuclides.

B. Estimates of Dose and Risk

The vast majority of NRC licensed facilities and non-DOE Federal facilities emit relatively small quantities of radionuclides, which cause correspondingly low doses to people living nearby. Most such facilities cause maximum radiation doses of less than 1 mrem/y; the total dose to the population living around a site rarely exceeds 1 or 2 person-rem per year of operations. The maximum corresponding lifetime risks of such exposures are estimated to be less than 1 in 50,000 for the individuals receiving the highest doses, and the total risk to the population surrounding a typical facility should be less than about 1 health effect per 500 years of operation.

These estimates were developed by using methods and assumptions discussed in Unit I.C. of this notice. It is important to recognize that the actual risk to specific individuals may differ greatly from these estimates because the circumstances involving the actual exposure may differ significantly from the assumptions used to make the estimates.

C. Control Technology

Some NRC-licensed facilities emit argon–41 and tritium mixed with large volumes of air. For this type of facility, virtually all of the dose is caused by argon–41. Demonstrated treatment technology to reduce argon–41 emissions is not available because argon is a noble gas and cannot be filtered or easily trapped. However, design features, operating procedures, and equipment maintenance can be used to minimize formation of argon–41 in these reactors. For example, since air contains a small percentage of argon–40, areas in which air is exposed to neutrons generated by the reactor are sources of argon–41 when argon–40 absorbs a neutron during reactor operation. In some situations, these areas can be purged with an inert gas to reduce the amount of argon–40 available before starting up the reactor. In other cases, sealing air leaks will reduce the amount of argon–41 that would be produced.

Most facilities emitting dust to which radionuclides are attached use conventional particulate removal technology, such as fabric filters, electrostatic precipitators, scrubbers, or high-efficiency particulate air filters.

D. The Proposed Standards

EPA is proposing that emissions of radionuclides from NRC-licensed facilities and non-DOE Federal facilities be limited to that amount that would cause a dose equivalent of 10 mrem/y to any organ of any individual living nearby. Uranium fuel cycle facilities and all particle accelerators are specifically not covered by this standard for reasons discussed Unit VII of this notice.

In proposing this standard, EPA examined emission levels from facilities in this category and estimated the dose these emissions cause for people living nearby. The highest doses are caused by research and test reactors emitting principally argon–41. The dose associated with the operation of these facilities is low and cannot be significantly reduced without major redesign and and reengineering of these facilities. Therefore, EPA has decided to proposed a standard at a level that can be met by existing facilities if they continue to use good management and operational controls to limit their emissions.

EPA believes that the proposed standard protects public health with an ample margin of safety. EPA estimates the risk associated with the proposed standard to be the same as for current practice for the individual receiving the highest dose. The uncertainty associated with estimates of risk is discussed in Units. I.C. and III. B. of this notice.

EPA requests comments on the proposed standards and the methodology used in deriving it.

E. Alternatives to the Proposed Standard

The Agency considered higher and lower dose limits than the one being proposed. Higher values were rejected because the proposed standard is currently being met by all facilities in this group. A lower limit was rejected because the dose associated with these emissions is very low and EPA does not believe it is reasonable to set a lower standard and force these facilities to close or reduce their hours of operations.

EPA considered not proposing a standard for this category of facility because the dose from the operations is generally very low. The Agency rejected this alternative because of the potential impact of new facilities or modifications to existing facilities; a standard will ensure that no facilities will emit radionuclides at unreasonably high levels.

EPA also considered requiring that these facilities submit reports documenting that their emissions are as low as practicable, as is being proposed for DOE facilities. Such a requirement would impose a very large paperwork burden on government and industry. Facilities in this category number in the tens of thousands. For EPA to implement such a requirement for this category would require monitoring and reporting by thousands of facilities and e substantial effort on the part of NRC or EPA to review the reports. This considerable effort would help ensure that emissions remain very low. However, because the risk associated with the proposed standard is already low. EPA does not believe the paperwork burden on government and industry is justified. Furthermore, EPA expects that facilities in this category

will, in practice, keep emission levels as low as practicable, both to ensure compliance with the proposed standard and as a matter of good radiation protection principles when dealing with hazardous materials.

F. Implementation of the Proposed Standards

For NRC licensed facilities, NRC will implement the standards subject to EPA oversight to ensure there is compliance with the standard, as is specified in a Memorandum of Understanding between EPA and NRC (45 FR 72980). Implementation will follow the established NRC practice, which is based on a review of control measures used by licensees and their effectiveness as determined by generic assessments.

For non-DOE Federal facilities, EPA will ensure compliance with the standards. EPA's implementation will use the models AIRDOS–EPA and RADRISK to perform pathway analysis and to calculate dose equivalents.

IV. Underground Uranium Mines

A. General Description

Uranium mining involves the handling of large quantities of ore containing uranium-238 and its decay products. The concentrations of these radionuclides in ore may be up to 1,000 times their concentration in other rocks and soils. After mining, the ore is shipped to a uranium mill where the uranium is separated for subsequent use in nuclear power reactors.

Uranium mining is generally carried out by either surface (open pit) or underground mining methods, depending on the depth of the ore deposit. In 1981, there were 167 underground mines and 50 open pit mines in operation in the United States. These mines accounted for about 80 percent of the uranium produced in this country.

All uranium mining in the United States now takes place in western States. In general, the mines are located in relatively remote, low population areas. In 1981, about 70 percent of domestic uranium ore production took place in New Mexico, Wyoming, and Texas.

EPA has evaluated radionuclide emissions from uranium mining activities. These evaluations show that radon-222 is the most significant radionuclide emitted to air. Radon-222 is released to air from underground mines in relatively high concentration through a series of ventilation shafts installed at appropriate locations along the mine haulage ways. These ventilation shafts provide sufficient air exchange in the working areas of the mine to keep the miners' exposures to radon decay products below the permissible limits. A recent study of 27 underground mines showed that radon-222 emissions to air from individual vents ranged from 2 to 9,000 Ci/y with an average of 900 Ci/y. The number of vents per mine ranged from 2 to 15 with an average of 6 vents per mine. The radon-222 released through these ventilation shafts can cause significant increases in the radon-222 concentration in ambient air in the vicinity of the mine vents.

EPA's evaluation of releases of radon-222 from uranium mines shows that radon-222 is released from surface mines in considerably smaller quantities and in more dilute concentrations than from underground mines. Therefore, radon-222 emissions from surface mines causes only small increases in the radon-222 concentrations in ambient air near the mines and concerns for the health of people near uranium mines is greatest for people living near underground mines.

B. Estimates of Exposure and Risk

Individuals living near underground uranium mines can be exposed to high levels of radon-222. This exposure generally occurs in structures built around the mines. Radon-222 enters the building and decays into other radionuclides which become attached to dust particles in the air. The concentration of these radionuclides build up in the air within the structures. EPA estimated the potential detriment to human health because of radon-222 emissions from uranium mines using the general assumptions discussed in Unit I.C. of this notice. It is important to recognize that the actual risk to individuals may differ greatly from these estimates because the circumstances involving the exposure may differ significantly from the assumptions used to make the estimates. Further, people need to be occupying a structure and not just standing outdoors for these estimates to be applicable.

It is estimated that an individual living 500 meters in the predominant wind direction from a large underground uranium mine will be exposed to a radon-222 concentration of 1 to 2 picocuries per liter (pCi/1) above background. Continuous exposure to *indoor* radon decay product concentrations (0.007–0.014 working level (WL)) produced by this radon-222 level might result in an increased lifetime risk of 1 to 2 in 100, although in areas where there are many mine vents clustered relatively close together, the risks could be as high as an order of magnitude greater. (A working level is a unit used to measure exposure to radon decay products).

Collective exposures for populations living near uranium mines are relatively low because these mines generally are located in low population areas. For example, the population risk due to radon-222 emissions from a large underground mine is estimated to be extremely small (about 1 health effect per 30 years of operation of the mine). Consequently, for underground uranium mines, the exposure to the general population is of considerably less public health concern than the exposure for the people that live very close to the mine vents.

C. Control Technology

There are no radon-222 emission control systems now in use in underground uranium mines. However, several methods for reducing the radon-222 concentration in mine air are available and have been used or tested for controlling radon-222 decay product concentrations in the mine itself. These methods, which primarily involve preventing radon-222 from entering the mine air through the use of sealants on the mine walls, bulkheading or backfilling the mined-out stopes, and mine pressurization can also reduce the radon-222 emissions to the outside air. EPA has carried out engineering evaluations of the cost and effectiveness of some of these methods in a hypothetical mine. These evaluations showed that such control methods would be relatively costly and not very effective. The study predicted radon-222 emission reductions from 14 to 49 percent at costs from $0.30 to $4.70 dollars per ton of ore mined.

Based on available information, EPA has concluded that no practical technology now exists for achieving satisfactory reductions in radon-222 emissions to air from underground uranium mines. The most effective procedure for limiting exposure to individuals is to provide for greater dispersion of the released radon-222. The Act indicates a preference for avoiding this type of control action to reduce health risks. However, in this situation, traditional emission control methods do not appear to be sufficiently effective in reducing the human health risks posed by release of radon-222 from underground uranium mine vents.

D. The Proposed Standard

EPA is proposing a standard that will limit the annual average radon-222 concentration in air due to emissions from an underground mine to 0.2 pCi/1 above background in any unrestricted

area. An unrestricted area is defined to be any area not under the control of the mine owner or a government agency. Under this proposed standard, for a typical, large underground mine using the modeling assumptions previously described, we estimate the lifetime risk to an individual will be on the order of about 1 in 500. For a case in which many mines are located close together, studies which estimate the hazard based on a lifetime exposure show that the potential risks would be higher. However, uranium mines have a limited useful lifetime, usually 5 to 15 years, which limits the period when radon-222 would be released. Further, several other assumptions used in these studies, such as the period of occupancy of the structure, are likely to be less severe in real cases. These factors are expected to make the actual remaining risk to individuals less than 1 in 500, possibly by one or two orders of magnitude, depending on the specific circumstances.

EPA chose a standard of 0.2 pCi/1 because higher values did not provide sufficient protection of public health, particularly when many mines are located close together. Values lower than the proposed standard were judged to be impractical because of the cost and difficulty in controlling additional land and the expense associated with other control measures compared to their effectivenss. EPA believes that the risks associated with the proposed standard are not unreasonable in comparison to the cost of additional control.

The standard can be met by one of the following procedures: (1) Reducing the percentage of time the mine operates, (2) increasing the effective height of the release, and (3) controlling additional land. EPA expects that the least expensive way to meet the standard is for the the mine operator to control the land around the mine so that people do not live in houses on the land. EPA believes that, on the average, compliance with the proposed standard can be achieved by controlling land within 2 kilometers of the mine vents. The cost to meet the standard by purchasing surrounding land and structures is estimated to be about 4 million dollars per year. This estimate was determined from an evaluation of the cost to control land within 2 kilometers of 29 large mines representing about 90% of the underground uranium mine or production

Based on 1981 production values, this cost represents a $0.30 per pound increase in the cost of producing uranium. This represents a 1% increase in production costs. Although the costs for the smaller mines accounting for the remaining ore production are not included in the estimate, these costs will be relatively small because the radon-222 emissions from these mines are expected to be small.

Owners and operators of underground uranium mines will be required to keep records of radon-222 emissions and radon-222 concentration projections consistent with other actions under the Act.

EPA requests comments on the proposed concentration limit of 0.2 pCi/1. EPA believes that the proposed standard is the most practical and effective way to limit the potential risk to individuals due to radon-222 emissions from underground uranium mines.

E. Alternative Standards

The development of standards for uranium mines is more difficult and complicated than for other sources emitting radionuclides into air. Therefore, the Agency requests public comment on other possible options for standards. In particular, comments are requested on appropriate limits, cost, feasibility, and significance for public health for the following options:

Option 1: Land Control Standard. This type of standard would establish an exclusion area of fixed distance from a mine vent. This area would be under the control of the mine owner or a government agency to prevent excessive exposure to individuals.

Option 2: Work Practice Standard. This standard would include requirements for use of one or more of the following techniques to reduce radon emissions: bulkheading worked-out stopes (including the use of charcoal absorbers on bleeder pipes), backfilling worked-out stopes, and using sealants on mine walls.

Option 3: Emission Standard. This type of standard would establish an emission limit in curies per year of radon-222 from a mine vent as a function of the distance from the vent to the nearest unrestricted area. The emission limit would be set at a value that would keep the radon-222 concentration in ambient air in unrestricted areas below some predetermined value above background.

V. Elemental Phosphorus Plants

A. General Description

About 10 percent of the phosphate rock mined in the United States is used to produce elemental phosphorus. Elemental phosphorus is used primarily for the production of high-grade phosphoric acid, phosphate based detergents, and organic chemicals. In 1977, approximately 285,000 metric tons of elemental phosphorus were produced from 4 million metric tons of phosphate rock.

Phosphate rock contains appreciable quantities of uranium and its decay products. The uranium concentration of phosphate rock ranges from about 20 to 200 parts per million (ppm), which is 10 to 100 times higher than the uranium concentration in most natural rocks and soil (2 ppm). The significant radionuclides present in phosphate rock are uranium-238, uranium-34, thorium-230, radium-226, radon-222, lead-210, and polonium-210. Because phosphate rock contains elevated concentrations of these radionuclides, handling and processing this material can, via dust particles, release radionuclides into the air. More importantly for elemental phosphorus plants, heating the phosphate rock to high temperatures in calciners and electric furnaces can volatilize lead-210 and polonium-210, resulting in the release of large quantities of these radionuclides in to the air.

There are eight elemental phosphorus plants in the United States; these plants are located in Florida, Idaho, Montana, and Tennessee. EPA measurements at three of these plants show that polonium-210 and lead-210 are the radionuclides released from these plants in largest quantities. Most of these emissions occur in calciner stack exhausts. Based on these measurements, it is estimated that a large plant processing phosphate rock containing 25 picocuries per gram of uranium-238 and its decay products and using low energy scrubbers on its calciner exhausts would release about 4 curies of polonium-210 and 2 curies of lead-210 per year into the air. Several of the presently operating elemental phosphorus plants may be releasing comparable quantities of polonium-210 and lead-210, and these emissions would represent the largest quantity of alpha-emitting radionuclides released as particulates into the air by any type of facility in the United States.

B. Estimates of Dose and Risk

The most significant hazard associated with radionuclide emissions to air from elemental phosphorus plants is the radiation dose received by individuals living near those plants. EPA estimates that the radionuclide emssions, primarily polonium-210 and lead-210, from a large elemental phosphorus plant will cause radiation doses of 45 mrem/y to the kidney and 36

mrem/y to the lung of the most exposed individual living near the plant. The lifetime risk to the maximally exposed individual associated with these doses is estimated to be about 1 in 10,000.

The risks to the populations living near elemental phosphorus plants are relatively low. EPA estimates that the potential health risk to the population living around a large plant is about 1 health effect per 100 years of plant operation and that the total risk from radionuclide emissions from all elemental phosphorus plants is about 1 health effect per 20 years of operation.

These estimates were developed using methods and assumptions discussed in Unit I.C. of this notice. It is important to recognize that the acutal risk to specific individuals may differ greatly from these estimates because the circumstances involving the exposure may differ significantly from the assumptions used to make the estimates.

C. Control Technology

Particulate emissions from calciner exhausts at elemental phosphorus plants are controlled through the use of wet scrubbers. Most plants use either spray towers or low-energy venturi scrubbers. Such systems are estimated to control particulate emissions to about 0.5 to 1.0 pound per ton of rock processed and are about 80 to 90 percent efficient for removal of polonium-210. One plant operates with two venturi-like scrubbers in series. Such a system should control particulate emissions to about 0.1 pound per ton of rock processed and is about 98 percent efficient for removal of polonium-210.

EPA has estimated the cost of installing high-energy venturi scrubbers on calciner stacks at large elemental phosphorus plants now operating with spray towers or low-energy scrubbers. The capital cost per plant for installing these scrubbers is about $3 million, and the annual operating cost is $1.5 million. A high-energy venturi scrubber is expected to be at least 98 percent efficient for polonium-210 removal and to reduce the emissions of this radionuclide for a large plant to less than 1 Ci/y. Lead-210 will be controlled at least as well because the scrubbers will remove lead with at least equal efficiency.

D. The Proposed Standard

EPA is proposing that the emissions of polonium-210 in the calciner off-gases at elemental phosphorus plants be limited to 1 Ci/y. EPA believes the use of best available technology at these facilities can achieve this standard. Limiting the polonium-210 emissions also effectively limits the lead-210 and other radionuclide emissions in the calciner off-gases. this standard will keep the radiation doses to individuals living near these plants to less than 10 mrem/y to the lung and to less than 15 mrem/y to the kidney. The lifetime risk associated with these doses is less than 3 in 100,000. EPA believes this will protect the individuals living nearby with an ample margin of safety. The assumptions and uncertainties associated with estimates of risk are discussed in Units I.C. and V.B. of this notice.

Complete information is not available on the polonium-210 emissions from all elemental phosphorous plants. Therefore, some uncertainty exists regarding the number of plants that would need to retrofit emission control systems. However, based on presently available information, EPA estimates that no more than two plants would need to install additional control systems to meet the proposed standard. These would be the large-capacity plants processing high-radionuclide-content phosphate rock. Installation of high-energy venturi scrubbers on the calciner exhausts of two plants would result in a capital expenditure of about $6 million and annual operating costs of $3 million per year.

Under the proposed standard, owners or operators of elemental phosphorus plants will be required to (a) measure the polonium-210 emissions from their calciner stacks and to report the results of these tests to EPA and (b) continuously monitor the pressure drop across their calciner scrubbers and to maintain records of these measurements for a minimum of two years.

EPA requests comments on the proposed values and the methodology used in arriving at them.

E. Alternatives to the Proposed Standard

The Agency considered proposing higher or lower values then 1 Ci/y. Higher values did not seem justified because they would either not significantly reduce the radiation doses to individuals living near these plants or would cost just as much to implement as the proposed standard. Lower values were also considered, but available information indicates that additional control technology is not feasible to meet lower levels.

The Agency also considered a standard expressed as curies/metric ton of phosphate rock processed. However, this type of standard may require emmission control retrofit by one or more additional plants even though their emissions of polonium-210 would be significantly less than 1 Ci/y. Since the primary purpose of the standard is to limit the annual radiation doses to the most exposed individual living near these plants, the Agency concluded that an annual emission limit, rather than an emission limit per unit of rack processed, is the more appropriate form of the standard.

VI. Sources for Which Standards Are Not Proposed

EPA has identified several source categories that emit radionuclides to air for which standards are not being proposed. These emissions comprise radionuclides that occur naturally in the environment but are released to air due to industrial processes. In addition to these sources, EPA is not proposing emission standards for uranium fuel cycle facilities, uranium mill tailings, management of high level radioactive wastes, and low energy accelerators. The reasons for these decisions are discussed in the following paragraphs. Additional supporting information may be found in the Docket and in the Background Information Document.

Estimates of risk used in this analysis were developed using methods and assumptions discussed in Unit I.C. of this notice. It is important to recognize that the actual risk to specific individuals may differ greatly from the estimates because the circumstances involving the actual exposure may differ greatly from the assumptions used to make the estimates.

A. Coal-Fired Boilers

Large, coal-fired boilers are used by utilities and industry to generate electricity and by industry to make process steam and to heat water for space heaters and industrial processes. When these boilers are operating, trace amounts of uranium, radium, thorium, and decay products of these radionuclides that are present in coal become incorporated into the fly ash and are emitted along with the particulates into the air. Technology that removes particulates will, therefore, also limit radionuclide emissions.

Particulate emissions from new utility boilers are controlled under Section III of the Act (43 FR 42154, September 19, 1978, revised by 44 FR 33613, June 11, 1979). These New Source Performance Standards (NSPS) require utility boilers constructed after September 19, 1978, to have best available technology that limits particulate emissions to 13 nanograms per Joule (ng/J) (0.03 pound/million Btu). To meet this emission standard, electrostatic precipitators (ESPs) or fabric filter systems are usually installed. Doses from utility

boiler radionuclide emissions under NSPS are low, less than 1 mrem/y to any organ, and there is no practical way to reduce them further since best available technology is already being used. Further reduction in emissions would require a second fabric filter or ESP in series with the first; this would be unreasonably expensive for the emission reduction achieved. Thus, radionuclide emission standards for new utility boilers would be either redundant or, if more restrictive, prohibitively expensive.

Particulate emissions from new large industrial boilers are controlled by NSPS that limit particulate matter to 43 ng/J (0.1 pound/million Btu). EPA plans to propose NSPS for smaller industrial boilers also; draft proposed limits have been circulated for comment. These standards should reduce particulate emissions to low levels and should correspondingly reduce doses to nearby individuals from radionuclide emissions to less than 1 mrem/y to any organ. With NSPS in place, radionuclide standards for industrial boilers would be redundant.

Existing utility and industrial boilers are regulated for particulate emissions by State Implementation Plans (SIPs) required by the Act. Limits vary for specific plants, but, in general, SIPs require large boilers located in populated areas to be well controlled with ESPs. Preliminary information indicates that retrofitting existing utility boilers to further reduce radionuclide emissions would cost approximately $15 billion for capital improvements and $3 billion a year to operate them. Total retrofitting of the industry with best available technology would reduce the estimated potential health effects by about 1 to 2 per year. For industrial boilers, the costs are about $3 billion for capital improvements and $0.7 billion to operate them. Total retrofitting of the industry with best available technology would reduce the estimated potential health effects by about 1 every three years. For both utility and industrial boilers, the costs are judged to be unreasonable in comparison to the reduction in dose and risk that would result.

The amount of radionuclides that could potentially be emitted by coal-fired boilers is strictly limited by the amount of uranium and thorium in the incoming coal. EPA has no reasons, therefore, to expect that massive releases of radionuclides will occur or that current emission rates will increase significantly. Under the current Federal and State regulatory programs, emissions should slowly decrease as old boilers are replaced.

In summary, EPA is not proposing standards for coal-fired boilers because existing emission controls that limit particulate releases also limit radionuclide releases. The risks to nearby individuals and the total risks to populations after application of controls already required are not large when compared to the cost of additional control technology. There is no potential for emissions to increase due to the limited amounts or radionuclides within the coal; rather, overall emissions will decrease with time as old plants are replaced with new ones with improved emission controls as required by the NSPS for particulate emissions.

EPA did consider the possibility that boilers may be using coal with radionuclide content that is significantly above average or that existing boilers may be operating in a manner that causes elevated emissions of radionuclides. If this is the case, there could be a subcategory of coal-fired boilers for which it would be appropriate to issue an emission standard. EPA requests comments and information on whether these situations do exist, their causes, their significance to public health, whether emission standards are needed, and what emission levels would be appropriate.

B. Phosphate Industry

The phosphate industry processes phosphate rock to produce fertilizers, detergents, animal feeds and other products. The production of fertilizer uses approximately 80 percent of the phosphate rock mined in the United States. Diammonium phosphate and triple superphosphate are the phosphate fertilizers produced in the largest quantities. Phosphate deposits contain large quantities of natural radioactivity, principally uranium-238 and members of its decay series. Uranium concentrations in phosphate deposits range from 10 to 100 times the concentration of uranium in other natural rocks and soils.

The processing of phosphate rock in dryers, grinders, and fertilizer plants results in the release of radionuclides into the air. As with coal-fired boilers, control techniques that remove particulates will also control radionuclide emissions and risks. Particulate emissions from the process exhausts of these plants are already well controlled, and the doses to individuals and populations from the radionuclides contained in the particulates are less than 15 mrem/y to any organ.

Particulate emissions from new or modified phosphate rock dryer and grinder facilities are already regulated by NSPS under Section 111 of the Act (47 FR 16582, April 16, 1982). To meet these standards, high-energy scrubbers of high-energy ESPs are usually installed on dryers, and fabric filters are installed on grinders. Particulate emissions from existing dryers and grinders are regulated under SIPs. About 20 percent ot the existing dryers already have controls equivalent to NSPS; the remaining dryers either employ low-energy or medium-energy scrubbers. About 75 percent of the existing grinders already have controls equivalent to NSPS; the remaining grinders use the equivalent of medium-energy scrubbers.

To retrofit all existing phosphate rock dryers with best available technology would require a capital expenditure of $44 million and an increase of $3 million in annual operating costs. This would reduce the maximum individual bone dose from 15 mrem/y to 3 mrem/y and avoid 1 health effect in 50 years of operations. To retrofit all existing phosphate grinders with best available technology would require a capital expenditure of $4 million but would not increase the annual operating cost. This would reduce the maximum individual bone dose from 1 mrem/y to 0.2 mrem/y and avoid 1 health effect in 500 years of operations.

Phosphate fertilizer plants use wet-scrubber systems on their process exhausts. These controls are needed to comply with NSPS (40 CFR Part 60, Subparts T through X) or SIPs for fluoride emissions. About 75 percent of the existing industry production capacity is controlled by both primary and secondary scrubbers. Scrubbers used to control fluoride emissions are also effective controls for particulate emissions.

To retrofit all existing fertilizer plants with secondary scrubbers on their diammonium phosphate and triple superphosphate process stacks would require capital costs of $14 million and would result in an increase of $1.5 million in annual operating costs. This would reduce the maximum individual bone dose from 2 mrem/y to 1 mrem/y and would avoid 1 health effect in 500 years of operations.

In summary, EPA is not proposing standards for phosphate rock dryers and grinders or phosphate fertilizer plants, because (1) the bone dose to individuals represent a small hazard to health compared to a similar dose to most other organs, (2) the potential for increased emissions is not present due to the limited amount of radionuclides in the phosphate rock, (3) other Clean Air Act standards require controls that also

reduce radionuclide emissions, and (4) the cost to further reduce radionuclide emissions is unreasonably large compared to the additional protection achieved.

About 25 percent of the phosphate rock used for fertilizer production is treated in calciners rather than dryers to remove organic matter prior to processing. Since calciners operate at significantly higher temperatures than dryers, this may result in the volatilization and release to air of significant quantities of polonium-210, similar to the emissions from elemental phosphorus plants. Radionuclide emission studies are being planned for phosphate rock calciner plants. However, no radionuclide emission data are available for calciners, and, therefore, EPA is unable to determine at this time that standards are needed for these facilities. EPA requests comments and information on these emissions, their significance to public health, whether emission standards are needed, and what limits would be appropriate.

C. Other Extraction Industries

Almost all industrial operations involving removal and processing of soils and rocks to recover valuable commodities release some radionuclides into the air. EPA has carried out studies of airborne radioactive emissions from such mining, milling, and smelting operations.

The industries studied include iron, copper, zinc, clay, limestone, fluorspar, and bauxite. These are relatively large industries and are, therefore, considered to have the greatest potential for emitting radioactive materials into the air.

Although the analysis of data from these stidies is not complete, the information available to the Agency at the present time shows that the radiation doses to individuals and populations from radionuclide emissions from these types of facilities are small and would not be reduced at reasonable cost. Therefore, EPA is not proposing standards for these parts of the extraction industry.

D. Uranium Fuel Cycle Facilities, Uranium Mill Tailings, and Management of High Level Waste

The Uranium Fuel Cycle (UFC) consists of operations associatd with production of electric power for public use by light-water-cooled reactors using uranium fuel. It includes light-water-cooled nuclear power plants and facilities that mill the uranium ore, enrich uranium, and fabricate and reprocess uranium fuel. EPA has promulgated emission standards for normal operations of the UFC under the Atomic Energy Act (40 CFR Part 190). These standards limit the annual dose equivalent to body organs of nearby individuals to 25 mrem/y (75 mrem/y for the thyroid) and limit the emissions of krypton-85, iodine-129, and other long-half-life, alpha-emitting, transuranium radionuclides. As a practical matter, the EPA standards and their implementation by the NRC require the use of best available technology, which keeps doses to individuals and populations to low levels. The estimated individual risk associated with 25 mrem/y to all organs for a lifetime is about 1 in 2000.

Uranium mill tailings remain after uranium ore is processed to remove the uranium. Altogether, there are many thousands of acres of these tailings at both inactive and active uranium mill sites, mosely in the Southwest. Large amounts of radon-222 are emitted to air from the piles due to the radium-226 remaining in the tailings after the uranium is removed. Congress addressed this problem through the Uranium Mill Tailings Radiation Control Act of 1978 (Pub. L. 95-604). Under this authority, EPA has active programs to promulgate standards requiring remedial actions that will, among other objectives, prevent these tailings from being moved and prevent radon from escaping after the piles become inactive. Standards have been promulgated for inactive mill sites and will soon be proposed for active mill sites.

The highly radioactive liquid or solid wastes from reprocessing spent nuclear fuel, or the spent fuel elements themselves if they are disposed of without reprocessing, are called "high level wastes". Over the last several years, the Federal government has intensified its program to develop and demonstrate a permanent disposal method for high level waste. As part of this effort, EPA has proposed standards to limit radiation exposure of members of the public from management of this waste prior to disposal (47 FR 58196, December 29, 1982). These proposed standards would limit the annual dose equivalent to any member of the public to 25 mrem/y to the whole body, 75 mrem/y to the thyroid, or 25 mrem/y to any other organ. Waste managment operations are also to be conducted so as to reduce exposures below these levels to the extent that this is reasonably achievable.

EPA is not proposing additional radionuclide standards for UFC facilities, uranium mill tailings, and high level wastes because the Agency believes that EPA standards established (or to be established) under other applicable authorities will protect public health with an ample margin of safety in the same way as an emission standard established under Section 112 of the Act.

E. Low Energy Accelerators

Accelerators, which impart energy to charged particles such as electrons, alpha particles, and protons, are used for a wide variety of applications, including radiography, activation analysis, food sterilization and preservation, radiation therapy, and research. There are over 1,200 accelerators in use in the United States, not including accelerators owned by DOE. This number has been growing at a rate of approximately 65 machines per year.

Accelerators other than those owned by the DOE operate at low energy levels (i.e., less energy is imparted to the particles). These machines emit very small quantities of radionuclides (specifically, carbon-11, carbon-14, nitrogen-13, oxygen-15, and argon-41) because they operate at relatively low energies. In addition, those accelerators using tritium targets may emit a small quantity of tritium, typically less than 1 Ci/y. The quantity of radionuclides produced is so small that the doses and health risks associated with those emissions are extremely low, generally several orders of magnitude less than other sources discussed in the proposed rule. Further, there is no practical way to reduce them. EPA is not proposing standards for accelerators because of the low doses, less than 1 microrem/y to nearby individuals, and because there is no potential for the doses from existing or new facilities to exceed this level significantly.

F. Request for Comments

EPA requests comments on its proposed decisions not to issue standards for radionuclide emissions from the categories of sources just described. These decisions will be reconsidered if additional information becomes available indicating that doses and risks are significantly greater, costs are significantly lower, or controls are more available than those on which EPA based its decisions.

If the Administrator decides not to issue standards for particular source categories, such decisions are likely to be accompanied by determinations that these decisions are of nationwide scope and effect under the terms of section 307(b) of the Act.

VIII. Miscellaneous

A. Docket

The Docket is an organized and complete file of all information

considered by EPA in the development of these proposed standards. The Docket allows interested persons to identify and locate documents so that they can effectively participate in the rulemaking process. It also serves as the record for judicial review.

A transcript of the hearing and all written statements will be placed in the Docket and will be available for inspection and copying during normal working hours.

B. Executive Order 12291

Under Executive Order 12291, issued February 17, 1981, EPA must judge whether a rule is a "major rule" and, therefore, subject to the requirement that a Regulatory Impact Analysis be prepared. EPA has detemined that this rule is not a major rule as that term is defined in Section 1(b) of the Executive Order.

EPA concluded that the rule is not major under the criteria of section 1(b) because the annual effect of the rule on the economy will be less than $100 million. It will not cause a major increase in costs or prices for any sector of the economy or for any geographic region. Also, it will not result in any significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States enterprises to compete with foreign enterprises in domestic or foreign markets.

This proposed rule was submitted to the Office of Management and Budget (OMB) prior to publication, as required by the Executive Order.

List of Subjects in 40 CFR Part 61

Air pollution control, Asbestos, Beryllium, Hazardous materials, Mercury, Vinyl chloride, Radionuclides.

C. Paperwork Reduction Act

The Paperwork Reduction Act of 1980 (Pub. L. 96-511) (PRA) requires that the Office of Management and Budget review reporting and recordkeeping requirements that constitute "information collection" as defined. Assuming, without deciding, that some or all of the proposed reporting and recordkeeping requirements constitute information collection within the meaning of the PRA, the PRA requires the Office of Management and Budget to review information collection activities to determine whether they are "necessary for the proper performance of the functions of the Agency" (section 3508).

This proposal, if promulgated, would impose reporting and recordkeeping requirements for one Federal agency and on owners and operators of elemental phosphorus plants and underground uranium mines.

EPA requests comments on the reasonableness of the information collection requirements and on the costs involved as compared to other means of compliance determinations.

D. Regulatory Flexibility Analysis

Section 603 of the Regulatory Flexibility Act, 5 U.S.C. 603, requires EPA to prepare and make available for comment an "initial regulatory flexibility analysis" in connection with any rulemaking for which there is a statutory requirement that a general notice of proposed rulemaking be published. The "initial regulatory analysis" describes the effect of the proposed rule on small business entities.

However, Section 604(b) of the Regulatory Flexibility Act provides that Section 603 "shall not apply to any proposed * * * rule if the head of the Agency certifies that the rule will not, if promulgated, have a significant economic impact on a substantial number of small entities."

EPA believes that virtually all small businesses covered by this proposed rule are already meeting the proposed standards. Therefore, this rule will have little or no impact on small businesses.

For the preceding reasons, I certify that this rule, if promulgated, will not have significant economic impact on a substantial number of small entities.

Dated: March 29, 1983.

Lee Thomas,

Acting Administrator.

It is proposed to amend Part 61 of chapter I of title 40 of the Code of Federal Regulations as follows:

1. By adding to the table of sections the following items:

Subpart K—National Emission Standards for Radionuclide Emissions from Department of Energy Facilities

Sec.
61.120 Designation of facilities.
61.121 Definitions.
61.122 Standard.
61.123 Emission monitoring and test procedures.
61.124 Compliance and reporting.

Subpart L—National Emission Standard for Radionuclide Emissions From Facilities Licensed by the Nuclear Regulatory Commission and Federal Facilities Not Covered by Subpart K

61.130 Applicability.
61.131 Definitions.
61.132 Standard.

Subpart M—National Emission Standard for Radionuclide Emissions From Underground Uranium Mines

61.140 Applicability.
61.141 Definitions.
61.142 Standard.
61.143 Emission tests.
61.144 Reporting.

Subpart N—National Emission Standard for Radionuclide Emissions From Elemental Phosphorous Plants

61.150 Applicability.
61.151 Definitions.
61.152 Standard.
61.153 Emission tests.
61.154 Test methods and procedures.
61.155 Monitoring of Operations.

* * * * *

Appendix B—Test Methods

* * * * *

Method 111—Determination of polonium-210 emissions from stationary sources.

Authority: Sec. 112 and 301(a), Clean Air Act, as amended [42 U.S.C. 7412, 7601(a)].

2. By adding the following Subpart K:

Subpart K—National Emission Standards for Radionuclide Emissions From Department of Energy Facilities

§ 61.120 Designation of facilities.

The provisions of this subpart apply to radiation dose equivalent values received by members of the public as the result of operations at facilities that are owned or operated by the Department of Energy and that emit radionuclides to air.

§ 61.121 Definitions.

(a) "Whole body" means all human organs, organ systems, and tissues exclusive of the integumentary system (skin) and cornea.

(b) "Organ" means any human organ or tissue exclusive of the integumentary system (skin) and the cornea.

(c) "Radionuclide" means any nuclide that emits radiation.

(d) "Dose equivalent" means the product of absorbed dose and appropriate factors to account for differences in biological effectiveness due to the quality of radiation and its distribution in the body. The unit of the dose equivalant is the rem.

§ 61.122 Standard.

Emissions of radionuclides to air from operations of Department of Energy facilities shall not exceed those amounts that cause a dose equivalent rate of 10 mrem/y to whole body or 30 mrem/y to any organ of any member of the public.

§ 61.123 Emission monitoring and test procedures.

To determine compliance with the standard, radionuclide emissions shall be determined and dose equivalent values to members of the public calculated using EPA approved sampling procedures, codes AIRDOSE-EPA and RADRISK, or other procedures

which EPA has determined to be suitable.

§ 61.124 Compliance and reporting.

DOE shall submit to EPA an annual report which includes the results of monitoring emissions from points subject to this standard and dose calculations for each site. The report shall also describe the DOE program for maintaining airborne radionuclide releases as low as practicable below the standard, including a discussion of current controls, new control equipment installed during the year, and a discussion of new controls that are under consideration.

3. By adding the following Subpart L:

Subpart L—National Emission Standards for Radionuclide Emissions From facilities Licensed by the Nuclear Regulatory Commission and Federal Facilities Not Covered by Subpart K

§ 61.130 Applicability.

The provisions of this subpart apply to NRC-licensed facilities and to facilities owned or operated by any Federal agency other than the Department of Energy, except that this subpart does not apply to facilities regulated under 40 CFR Part 190 or to any accelerator.

§ 61.131 Definitions.

(a) "Agreement State" means and State with which the Atomic Energy Commission or the Nuclear Regulatory Commission has entered into an effective agreement under subsectin 274(b) of the Atomic Energy Act of 1954, as amended.

(b) "Dose equivalent" means the product of absorbed dose and appropriate factors to account for differences in biological effectiveness due to the quality of radiation and its distribution in the body. The unit of the dose equivalent is the rem.

(c) "NRC/licensed facility" means any facility licensed by the Nuclear Regulatory Commission or any Agreement State to receive title to, receive, possess, use, transfer, or deliver any source, by-product, or special nuclear material.

(d) "Organ" means any human organ or tissue exclusive of the integumentary system (skin) and the cornea.

(e) "Radionuclide" means any nuclide that emits radiation.

§ 61.132 Standard.

(a) Emissions of radionuclides to air from facilities subject to this subpart shall not exceed those amounts that cause a dose equivalent rate of 10 mrem/y to any organ of any member of the public.

(b) This standard shall be implemented using pathway and dose equivalent calcuations based on EPA's codes AIRDOSE-EPA and RADRISK or modeling techniques which, in EPA's judgment, are as suitable for particular applications as the EPA codes.

4. By adding the following Subpart M:

Subpart M—National Emission Standard for Radionuclide Emission From Underground Uranium Mines

§ 61.140 Applicability.

The provisions of this subpart are applicable to owners or operators of underground uranium mines.

§ 61.141 Definitions.

(a) "Unrestricted area," as used in this subpart, means an area not under the control of the mine owner or operator or a governmental agency for the purpose of restricting the use or establishment of structures for residential purposes.

(b) "Mine vent" means a shaft extending from the working areas of an underground uranium mine to the earth's surface for the purpose of discharging ventilation air from the mine to the earth's atmosphere.

(c) "Curie" is a unit of radioacitivity equal to 37 billion nuclear transformations (decays) per second.

§ 61.142 Standard.

The radon-222 emissions to air from the mine vents of an underground uranium mine shall not result in an increase in the annual average randon-222 concentration in air in an unrestricted area in excess of 0.2 pCi/1.

§ 61.143 Emission tests.

(a) Unless a waiver of emission testing is obtained under 61.13, each mine owner or operator subject to 61.142 shall measure the radon-222 emissions from each of his mine vents:

(1) Within 90 days of the effective date of this rule, and annually thereafter, in the case of an existing source or a new source which has an initial startup date preceding the effective date of this rule; or

(2) Within 90 days of startup, and annually thereafter, in the case of a new source that did not have an initial startup date proceding the effective date.

(b) The Administrator shall be notified at least 30 days prior to an emission test so that EPA may, at its option, observe the test.

(c) Each emission test shall consist of three runs. The tests shall be conducted during normal operating and ventilation conditions. The average of all three runs shall apply in computing the emission rate.

(d) For use in calculating radon-222 concentrations in unrestricted areas under § 61.144, the annual emissions from each mine vent shall be determined by multiplying the radon-222 concentration measured in the air emitted from the mine vent by the total volume of air discharged through the vent over a one year period based on continuous operation of the ventilation system.

(e) Records of emission test results and other data needed to determine total emissions shall be retained at the source and made available for inspection by the Administrator for a minmium of 2 years.

§ 61.144 Reporting.

(a) Each owner or operator of a source subject to the requirements of § 61.142 shall calculate the average annual radon-222 concentration in air at the nearest unrestricted area to each of the mine vents from his mine using the following equation:

$$C_j = 0.1 \sum_i Q_i (X_{ij})^{-1.72}$$

Where

C_j = radon-222 concentration in picocuries per liter (pCi/1) at location j due to all vents from the mine.

Q_i = radon emission rate in kilocuries per year from vent i.

X_{ij} = distance in kilometers from mine vent i to location j.

(b) Rather than use the method prescribed in paragraph (a), an owner or operator of a mine may, subject to the approval of the Administrator, use dispersion factors based on site specific meteorology.

(c) The calculations performed under paragraph (a) or (b) shall be reported to the Administrator within 30 days of completion of the emission tests required under § 61.143.

5. By adding the following Subpart N:

Subpart N—National Emission Standard for Radionuclide Emission From Elemental Phosphorus Plants

§ 61.150 Applicability.

The provisions of this subpart are applicable to owners and operators of nodulizing kilns and electric furnaces at elemental phosphorus plants.

§ 61.151 Definitions.

(a) "Elemental phosphorus plant" means any facility that processes phosphate rock to produce elemental phosphorus using pyrometallurgical techniques.

(b) "Nodulizing kiln" means a unit in which phosphate rock is heated to convert it to a nodular form.

(c) "Electric furnace" means a unit in which the phosphate rock is heated with silica and coke to reduce the phosphate to elemental phosphorus.

(d) "Curie" is a unit of radioactivity equal to 37 billion nuclear transformations (decays) per second.

§ 61.152 Standard.

Emissions of polonium-210 to air from sources subject to this subpart shall not exceed 1 curie in a calendar year.

§ 51.153 Emission tests.

(a) Unless a waiver of emission testing is obtained under § 61.13, each owner or operator required to comply with § 61.152 shall test emissions from his source within the following time limits:

(1) Within 90 days of the effective date of this rule in the case of an existing source or a new source that has an initial startup date preceding the effective date of this rule; or

(2) Within 90 days of startup in the case of a new source that did not have an initial startup date preceding the effective date of this rule.

(b) The Administrator shall be notified at least 30 days prior to an emission test so that EPA may, at its option, observe the test.

(c) Each emission test shall consist of three runs. The phosphate rock processing rate during each test shall be recorded. The averge of all three runs shall apply in computing the emission rate. For determining compliance with the emission standard of § 61.152, the annual polonium-210 emissions shall be determined by multiplying the polonium-210 emission rate in curies per metric ton of phosphate rock processed by the annual phosphate rock processing rate in metric tons. In determining the annual phosphate rock processing rate, the values used for operating hours and operating capacity shall be values that will maximize the expected production rate. If the owner or operator of a source subject to this subpart changes his operation in a way that could change his emissions of polonium-210, he may determine his compliance with the requirements of this subpart on the basis of calculations using data from previous emission tests.

(d) All samples shall be analyzed, and polonium-210 emissions shall be determined within 30 days after the source test. All determinations shall be reported to the Administrator by a registered letter dispatched before the close of the next business day following such determination.

(e) Records of emission test results and other data needed to determine total emissions shall be retained at the source and made available for inspection by the Administrator for a minimum of 2 years.

§ 61.154 Test methods and procedures.

(a) Each owner or operator of a source required to test emissions under § 61.153, unless an eqivalent or alternate method has been approved by the Administrator, shall use the following test methods:

1. Test Method 1 of Appendix A to Part 60 shall be used to determine sample and velocity traverses;

2. Test Method 2 of Appendix A to Part 60 shall be used to determine velocity and volumetric flow rate;

3. Test Method 5 of Appendix A to Part 60 shall be used to collect particulate matter containing the polonium-210;

4. Test Method 111 of Appendix B to this part shall be used to determine the polonium-210 emissions.

§ 61.155 Monitoring of operations.

(a) The owner or operator of any source subject to this subpart using a wet scrubbing emission control device shall install, calibrate, maintain, and operate a monitoring device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be certified by the manufacturer to be accurate within ± 250 pascals (± 1 inch of water). Records of these measurements shall be maintained at the source and made available for inspection by the Administrator for a minimum of two years.

(b) For the purpose of conducting an emission test under § 61.153, the owner or operator of any source subject to the provisions of this subpart shall install, calibrate, maintain, and operate a device for measuring the phosphate rock feed to any affected nodulizing kiln. The measuring device used must be accurate to within ± 5 percent of the mass rate over its operating range.

Appendix B—[Amended]

6. By adding the following test method of Appendix B:

Method 111—Determination of Polonium-210 Emissions From Stationary Sources

Performance of this method should not be attempted by persons unfamiliar with the use of equipment for measuring radioactive disintegration rates.

1.0 Applicability and Principle

1.1 *Applicability.* This method is applicable to the determination of polonium-210 emissions in particulate samples collected in stack gases.

1.2 *Principle.* A particulate sample is collected from stack gases as described in Method 5 of Appendix A to 40 CFR Part 60. The polonium-210 in the sample is put in solution, deposited on a metal disc and the radioactive disintegration rate measured. Polonium in acid solution spontaneously deposits on surfaces of metals which are more electropositive than polonium. This principle is routinely used in the radiochemical analyses of polonium-210 (reference 1).

2.0 Apparatus

2.1 Alpha-counter photomultiplier tube, (5 cm), with associated electronics to record pulses.

2.2 Constant temperature bath at 85°C.

2.3 Polished nickel discs, 3.8 cm diameter, 0.6 mm thick.

2.4 Silver activated zinc sulfide screen.

2.5 Beakers, 400 ml, 150 ml.

2.6 Hot plate, electric.

2.7 Fume hood.

2.8 Teflon beakers, 150 ml.

Teflon is a registered trademark of DuPont Co.

3.0 Reagents

3.1 *Analysis.*

3.1.1 Ascorbic acid, reagent grade.

3.1.2 Distilled water.

3.1.3 Hydrochloric acid 12*M*, concentrated reagent grade.

3.1.4 Hydrofluoric acid 28*M*, reagent grade.

3.1.5 Nitric acid 16*M*, concentrated reagent grade.

3.1.6 Perchloric acid 12*M*, 72 percent reagent grade.

3.1.7 Sodium hydroxide 18*M*. Dissolve 720 g of sodium hydroxide pellets in distilled water and dilute to 1 liter.

3.1.8. Trichloroethylene.

3.2. *Standard solution.* Prepare calibrated solution of polonium-210 from supplier of this radionuclide. Known aliquots are to be used to establish efficiency of deposition.

4.0 Procedure

4.1 *Sample Preparation.*

4.1.1 Place filter collected by EPA Method 5 Part 60 in Teflon beaker, add 30 ml hydrofluoric acid and evaporate to dryness on hot plate in hood.

4.1.2 Repeat step 4.1.1 until glass fiber filter has been digested.

4.1.3 Add 100 ml 16*M* nitric acid to residue in Teflon beaker and evaporate to dryness. Do not overheat.

4.1.4 Add 50 ml 16*M* nitric acid to residue from step 4.1.3 and heat to 80°C.

4.1.5 Decant acid solution into glass beaker and add 10 ml 12*M* perchloric acid.

4.1.6 Heat acid mixture to perchloric acid fumes.

4.1.7 Adjust volume to 60 ml with distilled water and neutralize with 18*M* sodium hydroxide.

4.1.8 Dilute to 100 ml with distilled water and adjust solution to 0.5*M* in HCl by adding 4 ml 12*M* hydrochloric acid.

4.2 *Sample Analysis.* Analyze the solution for polonium-210 using any published method which involves the spontaneous electrodeposition of polonium-210, including the method described below:

4.2.1 Add 200 ml of ascorbic acid and heat solution to 85°C in constant temperature bath.

4.2.2 Melt a thin coating of polyethylene on the unpolished side of disc to prevent deposition. Adhesion of the polyethylene to the disc is enhanced by sanding the nickel surface with garnet paper.

4.2.3 Clean polished side with trichloroethylene, hydrochloric acid, and distilled water.

4.2.4 Suspended nickel disc in the solution using glass or plastic hook.

4.2.5 Maintain disc in solution for 3 hours while stirring the solution.

4.2.6 Remove nickel disc, rinse with distilled water and dry at room temperature.

4.3 Measurement of Polonium-210.

4.3.1 Position deposition side of nickel disc adjacent to zinc sulfide screen on photomultiplier tube and count pulses.

4.3.2 Establish background count rate by measuring counts over clean nickel discs.

4.3.3 Determine procedure efficiency by adding calibrated aliquots of polonium-210 to acid solution with clean filter and following procedure through radioassay step.

4.3.4 Determine counter efficiency by carefully evaporating known aliquots of polonium-210 on nickel disc and measuring count rate, comparing count rate to known disintegration rate as fraction.

5.0 Calculations

5.1 Calculate the curies of polonium-210 in the sample using the following equation:

$$A = \frac{C_T - C_B}{2.22 \times 10^{+12} (E_C)(E_P)(T)(D)}$$

A = Curies of polonium-210 in sample.
C_T = total sample counts for counting period.
C_B = background counts for counting period.
E_P = procedure efficiency.
E_C = counting efficiency.
T = counting time in minutes.
D = decay correction.

5.1.1 Decay Correction

$$\text{Decay correction (D)} = e^{-\frac{0.693(T)}{t_{1/2}}}$$

T = time in days from midpoint of collection time to the counting time.
$t_{1/2}$ = radiological half life of polonium-210, 138.4 days.

5.2 Procedure for Calculating Emissions.

Calculate the polonium-210 emission per metric ton of rock processed using the following equation:

$$E = \frac{AQ_S}{V_t M}$$

E = Curies of polonium-210 per metric ton of rock processed.
A = Curies of polonium-210 in sample from 5.1.
Q_S = Volumetric flow rate of effluent stream in m^3/h.
V_t = Total volume of air sampled in m^3.
M = Rock processing rate during sampling in metric tons/hr.

6.0 References

1. Blanchard, Richard L., Rapid Determination of Lead-210 and Polonium-210 in Environmental Samples by Deposition on Nickel, Anal. Chem., *38*, 189 (1966).

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BILLING CODE 6560-50-M

4

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 61

[AD-FRL-3072-7]

National Emission Standards for Hazardous Air Pollutants; Review and Revision of the Standards for Mercury

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final Rule; Review.

SUMMARY: Today's action promulgates revisions to the national emission standards for the hazardous air pollutant mercury [Chemical Abstract Service (CAS) Registry Number 7439-97-6]. Revisions were proposed in the Federal Register on December 26, 1984. These revisions add monitoring, reporting, and one-time emission testing requirements to the standards for mercury-cell chlor-alkali plants and allow an owner or operator the option of developing and submitting for approval a plant-specific monitoring plan. The revisions also allow the owner or operator of any facility affected by 40 CFR Part 61, Subpart E, up to 15 days to verify the validity of source test data prior to reporting the results to the Administrator.

EFFECTIVE DATE: March 19, 1987. These revisions become effective upon promulgation and apply to all new and existing affected facilities.

Under section 307(b)(1) of the Clean Air Act, judicial review of the actions taken by this notice is available *only* by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication. Under section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: *Review Documents.* The document summarizing emissions information gathered during the review of the standards may be obtained from the EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Review of National Emission Standards for Mercury," EPA-450/3-84-014b.

The document summarizing current information on the potential health effects associated with mercury exposures may be obtained from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22161, telephone number (703) 487-4650 (NTIS stock number PB-85-123925). Refer to "Mercury Health Effects Update," EPA-600/8-84-019F, August 1984. The price of the document, including shipping, is $19.95.

Docket. Docket No. A-82-41, containing information considered by EPA in developing the revisions, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, West Tower Lobby, Gallery 1, Waterside Mall, 401 M Street, SW., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: *Policy issues:* Ms. Dianne Byrne or Mr. Gil Wood, Standards Development Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578 *Technical issues:* Mr. John Copeland or Dr. James Crowder, Industrial Studies Branch, Emission Standards and Engineering Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5601.

SUPPLEMENTARY INFORMATION:

I. Summary of Review and Revisions

The national emission standards for mercury limit emissions from mercury ore processing facilities, sludge incineration and drying plants, and mercury-cell chlor-alkali plants. During its review of the standards, the EPA identified two areas in which revisions were warranted. The first area pertains to the appropriate amount of time, following completion of performance tests, that should be provided for reporting the results of those tests to the Administrator. The standards allowed 30 days following completion of the performance tests for the samples to be analyzed and emissions to be determined and required that the results be reported on the day after the determination was made. These revisions change that requirement. An owner or operator is now allowed 15 days after the determination of emissions to notify the Administrator of the test results. The additional 2 weeks are to provide time for the results to be reviewed and verified at the source before they are sent to the Administrator.

The second area in which revisions to the standards were warranted pertains to the monitoring and recordkeeping requirements for chlor-alkali plants. Compliance data for the hydrogen and end box ventilation streams at mercury-cell chlor-alkali plants indicated that, while many plants emit at levels just below the standard during normal operations, excess emissions have occurred during periods of control systems failures. To ensure that control systems are properly operated and maintained on a continuous basis, specific monitoring, recordkeeping, and reporting requirements have been added to the standards as well as a requirement for a one-time performance test. These requirements were fully described in the preamble to the proposed revisions (49 FR 50146, December 26, 1984).

In response to comments received on the proposed requirements, an alternative monitoring/recordkeeping/reporting provision has been added to the standards. This alternative allows each owner or operator of a mercury-cell chlor-alkali plant the option of developing and submitting for approval a plant-specific monitoring plan. To be approved, an alternative monitoring plan must adhere to the guidelines that are provided in the regulation.

The proposed standards required each owner or operator of a mercury-cell chlor-alkali plant that uses housekeeping practices to comply with the standard for cell room ventilation systems to maintain daily records of all leaks or spills of mercury in the cell room. These requirements have not changed.

As explained in the preamble to the proposed revisions and in the background document for the promulgated standards, the review of the standards did not indicate a need to revise the emission limits for the three source categories that are covered by the standards or to regulate additional sources of mercury emissions under these standards at this time.

II. Summary of Impacts of the Revisions

Extending the time limit for the submission of test data is intended to improve the quality of test results that are submitted and should have no environmental, economic, cost or energy impacts.

The addition of monitoring, recordkeeping, and reporting requirements for mercury-cell chlor-alkali plants will benefit the environment by encouraging plant operators to adopt the best practices for operating and maintaining process equipment and control devices. The additional reduction in mercury emissions has not been quantified. The average yearly cost to each plant during the first 3 years that the revisions are in

effect would be approximately $9,000. Most of this cost is attributable to the one-time performance test.

III. Public Participation

Prior to proposal of the revisions, interested parties were advised by public notice in the Federal Register (48 FR 50606, November 2, 1983) of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss recommended revisions to the mercury standard. This meeting was held on November 29, 1983. The meeting was open to the public, and each attendee was given an opportunity to comment on the standards recommended for proposal.

The proposed revisions were published in the Federal Register on December 26, 1984 (49 FR 50146). The preamble to the proposed revisions discussed the availability of the review document, which summarized the emissions information gathered during the review, and of the health effects document, which summarized current information on potential health effects associated with mercury exposures. Public comments were solicited at the time of proposal, and copies of the documents were distributed to interested parties.

To provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards, the opportunity for a public hearing was provided. However, a public hearing was not requested. The public comment period was from December 26, 1984, to March 13, 1985. Ten comment letters were received concerning issues relative to the proposed revisions and to the conclusions drawn as a result of the review. The comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the proposed revisions.

IV. Major Comments Received and Changes to the Proposed Revisions

The Agency received two major comments on the proposed monitoring and recordkeeping requirements for mercury-cell chlor-alkali plants. Chlor-alkali plant representatives commented that the standards should allow submittal (to the Administrator) of plant-specific compliance plans as an alternative to the proposed monitoring requirements. Various reasons supporting such a provision were provided by the commenters (and are summarized in section 2.1 of the review document). In response to these comments, the standards were revised to provide for the option of submittal of alternative plant-specific monitoring plans. Owners and operators who elect to submit such plans must adhere to the seven guidelines stated in § 61.55(c) of the regulation. The monitoring plan must ensure not only compliance with the emission limits but also proper operation and maintenance of emissions control systems.

Several commenters believed that the requirement to record all incidences of mercury leaks or spills should be changed to require recording only incidences of unpredictable or significant leaks or spills that require immediate corrective actions. While the Agency agrees that the leaks or spills of primary interest are those that are "significant," neither the Agency nor representatives from several chlor-alkali companies could offer an acceptable definition of a "significant" leak or spill. Without such a definition, the commenters' request could not be adopted.

One major comment was received in the area of EPA's evaluation of indirect exposures to mercury emissions. The commenter claimed that the Agency's ambient air guideline of 1.0 microgram of mercury per cubic meter of air was based solely on the health effects of inhaled mercury and ignored exposures to mercury emissions that are deposited on land, water, or other surfaces. This commenter believed a re-evaluation of the ambient guideline level was warranted and that the re-evaluation should take into account total human exposures to mercury, including deposited mercury in its more toxic methylated forms.

As stated in section 2.5 of the review document, the Agency considered mercury exposures from dietary ingestion as well as from inhalation in setting the ambient air guideline level. The guideline level also includes a safety factor of ten. However, the effects of mercury emissions on other environments (such as drinking water) and the accumulation of methyl mercury in food (primarily fish) were not fully addressed in the NESHAP review. The EPA is presently reviewing available information concerning these effects, and studies are currently underway to gather the necessary data. These include studies of biochemical mechanisms (for example, the biochemical cycling of mercury) and health and environmental effects (for example, the bioaccumulation of methylmercury in fish) from the deposition of mercury. A preliminary report of the results of studies addressing the bioaccumulation of mercury in fish (the primary source of ingested mercury) is scheduled for 1989 with an integrated report on mercury bioaccumulation scheduled for 1992. As the results of these studies become available, the Agency will take action as appropriate. However, at this time, the Agency does not have a sufficient basis for revising the ambient guideline level.

One commenter believed the Agency should re-evaluate its decision not to regulate mercury emissions from power plants. This commenter believed the Agency should revise its calculations of mercury emissions to include coals with higher mercury contents than those assumed in the calculations. The commenter referred to reports of mercury concentrations in some American coals as high as 1.6 parts per million (ppm), a level four times higher than the concentration that was used in the Agency's analysis. He stated that the Agency cannot conclude that the ambient guideline will not be exceeded until an analysis of the ambient concentrations expected from plants burning high-mercury coals is completed.

The commenter also objected to EPA's approach to regulating toxic emissions from coal-fired boilers. He stated that by analyzing toxic components of boiler emissions one-by-one, there is a strong bias against control since only a fraction of the total health risk is compared with the total control cost. The commenter believed that EPA should abandon this approach and should require the use of particulate control techniques to capture all toxic emissions, including mercury.

To examine the potential for mercury emissions from coal-fired power plants to exceed the ambient air guideline, the Agency reviewed the data on the mercury content of coals available in the United States (Docket item IV-B-1). The highest mercury level reported for the 48 contiguous states is 8 parts per million (ppm) for subbituminous coal and 3.3 ppm for bituminous coal with an average of 0.1 ppm for subbituminous coal and 0.21 ppm for bituminous coal. The worst case estimates for a large 4000 megawatt (MW) coal-fired power plant firing 8 ppm subbituminous coal is 870 pounds of mercury per day. According to dispersion estimates, a 4000 MW plant emitting 790 pounds of mercury per day would cause a maximum ground level concentration of 1.0 $\mu g/m^3$. This indicates that in the extreme case a large coal-fired power plant could emit mercury at levels high enough to exceed the ambient guideline. However, typically, mercury emissions from coal-fired power plants are expected to be well below the ambient guideline level.

The Agency is currently studying the combined effect of identified trace

element (including mercury) emissions from fossil-fuel combustion. For mercury, estimates are being made of nationwide emissions and of maximum concentrations associated with four sectors of coal burning: utility, industrial, commercial, and residential combustors. The results of this study will be used to determine the need and appropriate mechanism for regulating mercury emissions from fossil-fuel combustion.

Another major comment received pertained to mercury emissions from synthetic fuel processes. The commenter stated that there are data indicating that mercury emissions from oil shale retort operations can equal or exceed emissions from the currently regulated source categories. He believed these data demonstrate the need to set a national emission standard for mercury emissions from oil shale retorting and the need to examine the potential for mercury emissions from other synthetic fuel processes that are under active consideration.

At the present time there is only one retort plant in operation in the United States that is capable of processing more than 100 tons per day of raw shale to produce crude oil. Estimates of mercury emissions from this operation indicate that ambient mercury levels would be less than 0.04 $\mu g/m^3$, a level well below the ambient guideline level of 1.0 $\mu g/m^3$ (Docket item IV-A-2).

Construction of new retort operations or startup of existing plants that have been shut down is not anticipated in the near future. Furthermore, projections of mercury emissions from hypothetical commercial-scale operations indicate that emissions from a large size facility would still be below the ambient guideline level (Docket item IV-A-2).

In view of the low level of emissions from the oil shale retort that is currently in operation and the lack of anticipated growth in this industry in the near future, oil shale retorting operations are not being added as a source category to be regulated by the current mercury NESHAP. If oil shale retort operations become economically feasible, the Agency will review its decision not to regulate mercury emissions from these operations under these standards.

V. Administrative

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket, except for interagency review materials, will serve as the record in case of judicial review [section 307(d)(7)(A)].

As prescribed by section 112, the promulgation of these standards was preceded by the Administrator's earlier determination that mercury is a hazardous air pollutant. This determination was based on the finding that previously unregulated mercury emissions might cause or contribute to an increase in serious irreversible, or incapacitating reversible, illness. The intent of the standards is to protect the public health with an ample margin of safety. In accordance with section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

This regulation will be reviewed again 5 years from the date of this promulgation. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative control methods, enforceability, improvements in emission control technology, and reporting requirements.

Information collection requirements associated with this regulation (those included in 40 CFR Part 61, Subpart A and Subpart E) have been approved by the Office of Management and Budget (OMB) under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* and have been assigned OMB control number 2060-0097.

Under Executive Order 12291, EPA is required to judge whether a regulation is a "major rule" and therefore subject to the requirements of a regulatory impact analysis (RIA). The Agency has determined that this regulation would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule." This regulation will not have an annual effect on the economy of $100 million or more, result in a major increase in costs or prices, or have significant adverse effects on competition, employment, investment productivity, or innovation. The Agency has, therefore, concluded that this regulation is not a "major rule" under Executive Order 12291.

The Regulatory Flexibility Act of 1980 requires the identification of potentially adverse impacts of Federal regulations upon a substantial number of small business entities. The Act specifically requires the completion of a Regulatory Flexibility Analysis in those instances where small business impacts are possible. None of the companies affected by these revisions meets the Small Business Administration definition of a small business, and thus, no regulatory flexibility analysis was required.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 61

Air pollution control, Asbestos, Beryllium, Hazardous substances, Mercury, Radionuclides, Reporting and recordkeeping requirements, Vinyl chloride.

Dated: March 11, 1987.

Lee M. Thomas,

Administrator.

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

For reasons set out in the preamble, 40 CFR Part 61, Subpart E, is amended as set forth below.

1. The authority citation for Part 61 continues to read as follows:

Authority: 42 U.S.C. 7412, 7414, and 7601(a).

2. Section 61.53 is amended by revising paragraphs (a)(4), (b)(4), (c)(4), and (d)(5) to read as follows:

§ 61.53 Stack sampling.

(a) * * *

(4) All samples shall be analyzed and mercury emissions shall be determined within 30 days after the stack test. Each determination shall be reported to the Administrator by a registered letter dispatched within 15 calendar days following the date such determination is completed.

* * * * *

(b) * * *

(4) All samples shall be analyzed and mercury emissions shall be determined within 30 days after the stack test. Each determination shall be reported to the Administrator by a registered letter dispatched within 15 calendar days following the date such determination is completed.

* * * * *

(c) * * *

(4) An owner or operator may carry out approved design, maintenance, and housekeeping practices. A list of approved practices is provided in

Appendix A of "Review of National Emission Standards for Mercury," EPA–450/3–84–014a, December 1984. Copies are available from EPA's Central Docket Section, Docket item number A–84–41, III–B–1.

(d) * * *

(5) All samples shall be analyzed and mercury emissions shall be determined within 30 days after the stack test. Each determination shall be reported to the Administrator by a registered letter dispatched within 15 calendar days following the date such determination is completed.

* * * * *

3. Section 61.54 is amended by revising paragraph (f) to read as follows:

§ 61.54 Sludge sampling.

* * * * *

(f) All sludge samples shall be analyzed for mercury content within 30 days after the sludge sample is collected. Each determination shall be reported to the Administrator by a registered letter dispatched within 15 calendar days following the date such determination is completed.

* * * * *

4. Section 61.55 is amended by revising the title and paragraph (a) and by adding paragraphs (b), (c), and (d) as follows:

§ 61.55 Monitoring of emissions and operations.

(a) Wastewater treatment plant sludge incineration and drying plants. All the sources for which mercury emissions exceed 1,600 g per 24-hour period, demonstrated either by stack sampling according to § 61.53 or sludge sampling according to § 61.54, shall monitor mercury emissions at intervals of at least once per year by use of Method 105 of Appendix B or the procedures specified in § 61.53 (d) (2) and (4). The results of monitoring shall be reported and retained according to § 61.53(d) (5) and (6) or § 61.54 (f) and (g).

(b) Mercury cell chlor-alkali plants—hydrogen and end-box ventilation gas streams.

(1) The owner or operator of each mercury cell chlor-alkali plant shall, within 1 year of the date of publication of these amendments or within 1 year of startup for a plant with initial startup after the date of publication, perform a mercury emission test that demonstrates compliance with the emission limits in § 61.52, on the hydrogen stream by Reference Method 102 and on the end-box stream by Reference Method 101 for the purpose of establishing limits for parameters to be monitored.

(2) During tests specified in paragraph (b)(1) of this section, the following control device parameters shall be monitored, except as provided in paragraph (c) of this section, and recorded manually or automatically at least once every 15 minutes:

(i) The exit gas temperature from uncontrolled streams;

(ii) The outlet temperature of the gas stream for the final (i.e., the farthest downstream) cooling system when no control devices other than coolers and demisters are used;

(iii) The outlet temperature of the gas stream from the final cooling system when the cooling system is followed by a molecular sieve or carbon adsorber;

(iv) Outlet concentration of available chlorine, pH, liquid flow rate, and inlet gas temperature of chlorinated brine scrubbers and hypochlorite scrubbers;

(v) The liquid flow rate and exit gas temperature for water scrubbers;

(vi) The inlet gas temperature of carbon adsorption systems; and

(vii) The temperature during the heating phase of the regeneration cycle for carbon adsorbers or molecular sieves.

(3) The recorded parameters in paragraphs (b)(2)(i) through (b)(2)(vi) of this section shall be averaged over the test period (a minimum of 6 hours) to provide an average number. The highest temperature reading that is measured in paragraph (b)(2)(vii) of this section is to be identified as the reference temperature for use in paragraph (b)(6)(ii) of this section.

(4)(i) Immediately following completion of the emission tests specified in paragraph (b)(1) of this section, the owner or operator of a mercury cell chlor-alkali plant shall monitor and record manually or automatically at least once per hour the same parameters specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section.

(ii) Immediately following completion of the emission tests specified in paragraph (b)(1) of this section, the owner or operator shall monitor and record manually or automatically, during each heating phase of the regeneration cycle, the temperature specified in paragraph (b)(2)(vii) of this section.

(5) Monitoring devices used in accordance with paragraphs (b)(2) and (b)(4) of this section shall be certified by their manufacturer to be accurate to within 10 percent, and shall be operated, maintained, and calibrated according to the manufacturer's instructions. Records of the certifications and calibrations shall be retained at the chlor-alkali plant and made available for inspection by the Administrator as follows: Certification, for as long as the device is used for this purpose; calibration for a minimum of 2 years.

(6)(i) When the hourly value of a parameter monitored in accordance with paragraph (b)(4)(i) of this section exceeds, or in the case of liquid flow rate and available chlorine falls below the value of that same parameter determined in paragraph (b)(2) of this section for 24 consecutive hours, the Administrator is to be notified within the next 10 days.

(ii) When the maximum hourly value of the temperature measured in accordance with paragraph (b)(4)(ii) of this section is below the reference temperature recorded according to paragraph (b)(3) of this section for three consecutive regeneration cycles, the Administrator is to be notified within the next 10 days.

(7) Semiannual reports shall be submitted to the Administrator indicating the time and date on which the hourly value of each parameter monitored according to paragraphs (b)(4)(i) and (b)(4)(ii) of this section fell outside the value of that same parameter determined under paragraph (b)(3) of this section; and corrective action taken, and the time and date of the corrective action. Parameter excursions will be considered unacceptable operation and maintenance of the emission control system. In addition, while compliance with the emission limits is determined primarily by conducting a performance test according to the procedures in § 61.53(b), reports of parameter excursions may be used as evidence in judging the duration of a violation that is determined by a performance test.

(8) Semiannual reports required in paragraph (b)(7) of this section shall be submitted to the Administrator on September 15 and March 15 of each year. The first semiannual report is to be submitted following the first full 6 month reporting period. The semiannual report due on September 15 (March 15) shall include all excursions monitored through August 31 (February 28) of the same calendar year.

(c) As an alternative to the monitoring, recordkeeping, and reporting requirements in paragraphs (b)(2) through (8) of this section, an owner or operator may develop and submit for the Administrator's review and approval a plant-specific monitoring plan. To be approved, such a plan must ensure not only compliance with the emission limits of § 61.52(a) but also proper operation and maintenance of emissions control systems. Any site-specific monitoring

plan submitted must, at a minimum, include the following:

(1) Identification of the critical parameter or parameters for the hydrogen stream and for the end-box ventilation stream that are to be monitored and an explanation of why the critical parameter(s) selected is the best indicator of proper control system performance and of mercury emission rates.

(2) Identification of the maximum or minimum value of each parameter (e.g., degrees temperature, concentration of mercury) that is not to be exceeded. The level(s) is to be directly correlated to the results of a performance test, conducted no more than 180 days prior to submittal of the plan, when the facility was in compliance with the emission limits of § 61.52(a).

(3) Designation of the frequency for recording the parameter measurements, with justification if the frequency is less than hourly. A longer recording frequency must be justified on the basis of the amount of time that could elapse during periods of process or control system upsets before the emission limits would be exceeded, and consideration is to be given to the time that would be necessary to repair the failure.

(4) Designation of the immediate actions to be taken in the event of an excursion beyond the value of the parameter established in 2.

(5) Provisions for reporting, semiannually, parameter excursions and the corrective actions taken, and provisions for reporting within 10 days any significant excursion.

(6) Identification of the accuracy of the monitoring device(s) or of the readings obtained.

(7) Recordkeeping requirements for certifications and calibrations.

(d) Mercury cell chlor-alkali plants—cell room ventilation system.

(1) Stationary sources determining cell room emissions in accordance with § 61.53(c)(4) shall maintain daily records of all leaks or spills of mercury. The records shall indicate the amount, location, time, and date the leaks or spills occurred, identify the cause of the leak or spill, state the immediate steps taken to minimize mercury emissions and steps taken to prevent future occurrences, and provide the time and date on which corrective steps were taken.

(2) The results of monitoring shall be recorded, retained at the source, and made available for inspection by the Administrator for a minimum of 2 years.

(Approved by the Office of Management and Budget under control number 2060-0097)

5. Section 61.56 is added to Subpart E to read as follows:

§ 61.56 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 112(d) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: Sections 61.53(c)(4) and 61.55(d). The authorities not delegated to States listed are in addition to the authorities in the General Provisions, Subpart A of 40 CFR Part 61, that will not be delegated to States (§§ 61.04(b), 61.12(d)(1), and 61.13(h)(1)(ii)).

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5

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TOGETHER WITH

A SECTION-BY-SECTION INDEX

PREPARED BY THE

ENVIRONMENT AND NATURAL RESOURCES POLICY DIVISION

OF THE

CONGRESSIONAL RESEARCH SERVICE

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Pennsylvania has made significant strides in controlling utility emissions of sulfur dioxide. Of the 9 scrubbers in Pennsylvania, 6 are within 25 miles of downtown Pittsburgh. Yet with all this behind us, the State as a whole is still one of the top 5 emitters of SO_2 in the Nation.

Because of the unique character of the State we had a number of problems with the President's bill. Some utilities that had already installed scrubbers were not given credit for previous efforts, or worse, due to the economic conditions for previous efforts, or worse, due to the economic conditions in the baseline years, they would not be given enough credit to run their clean plants. In addition, a utility that had hoped to shut down several old small units as a part of its compliance realized that it would not be able to use the allowances generated by the shutdown, and the plants that did need to do more to clean their emissions found that the bill's date and reduction targets limited their options in a way that would cost their customers much more money.

Each of these problems is now addressed. The provisions on baselines and credits for clean utilities will enable clean plants to run effectively. The trading and allowance provisions adopted in the committee will allow more flexibility for dirty plants. And many of the technical problems with the bill have been cleaned up including the removal of one clean plant in Pennsylvania that had mistakenly been added to the list of 107 plants for first phase reductions.

I would especially like to thank the conference committee for adopting several amendments, amendments I offered to promote development and use of clean coal technologies. With these additions, cleaning up the air and developing our Nation's most abundant form of domestic fossil energy are compatible. One amendment expanded the number of technologies eligible for special incentives from the five in the President's bill to any other boiler technology that achieves better pollution control of more than one pollutant and is more efficient than conventional boilers with a conventional scrubber.

My second amendment would allow a utility to comply using clean coal technology at a new site if the old plant is retired. This provision prevents the locking in of a utility at a site that should be abandoned or is too small when it repowers. Without this flexibility, the bill may discourage what is a commonsense compliance option.

Third, I offered an amendment that allows a utility which has tried and failed to comply with a clean coal technology to switch to another technology without penalty.

Finally, I want to thank the conference committee and particularly Mr. Dingell and Mr. Sharp for assisting my local utility, Duquesne Light and General Public Utilities costing western Pennsylvania 2,000 jobs.

It is a real tribute to many Members of Congress and to the President that this Clean Air Act bill is before the House after a 10-year stalemate. As a 12-year member of a core group that pressed to strengthen the law, I am pleased to have been a part of this historic effort to give us, our children, and our grandchildren cleaner air. There could hardly be a more basic commodity than the air we breathe. This is a big step toward preserving it--and preserving the planet.

Mr. OXLEY. Mr. Speaker, after more than a year of debate which culminates over a decade of work, we are about to cast the final vote on a major rewrite of the Clean Air Act. In 1977 when the Clean Air Act was last amended, it was assumed that Congress would

amend this measure on a regular basis. However, for over 10 years, we could not narrow our differences, find middle ground, and pass a comprehensive clean air bill.

Last July, President Bush helped break the stalemate when he introduced the bill before us which includes provisions addressing industrial and automobile emissions, air toxics, and acid rain. Few environmental bills have been this complex or have the potential for disruption to our economy as this one. It pitted the environment against the economy, the East against the West, and one industry against another. To reconcile these issues, the conference committee had to make many difficult decisions.

I have been among the most skeptical about this bill because I wanted to ensure fairness to my home State of Ohio, particularly regarding the need for further acid rain controls and the benefits of those controls. Further, I wanted to provide clarity with the American people as to the costs of the bill. Conservative estimates indicate Americans will pay between $25 and $50 billion a year for cleaner air. To achieve this goal of improved health and welfare for our constituents, we will be asking them to pay the price through job losses, higher consumer product prices, high utility rates; in other words through changed life styles.

While this final bill is far from perfect, I believe we have come a long way toward the President's goal of balance and reasonableness. Underlying President Bush's clean air legislation was the desire to not only protect human health but to improve the quality of life of all Americans. It is my belief that this landmark legislation represents our best effort to negotiate a balance between the multitude of interests we represent and ensure that as a result, Americans will be better off, not worse off.

I am particularly pleased that we could blunt the impact on Ohio by including in the final agreement a provision which gives 200,000 additional allowances to Ohio, Indiana, and Illinois in phase I, and 50,000 new allowances to nine Midwestern States in phase II. We were also able to provide some assistance for two unique problems in my home State, the Zimmer plant, currently under construction, and Ohio Edison's small units which are the most costly and difficult to retrofit with scrubbers.

One of the key components of President Bush's bill was the concept of allowing the market to encourage reductions in pollution. This provision also caused divisions between the Midwest and the other States. To eliminate the argument that the Midwest would hoard allowances, and not give access to utilities in other States, I am happy to say that my proposal for auctioning allowances which was a part of the acid rain compromise adopted during consideration by the Energy and Commerce Committee has been retained by the conference. This mechanism will provide money to Midwest utilities faster and will also help to ensure that allowances are available to utilities across [sic]

Mr. Speaker, throughout the development of this legislation, we have worked to ensure that environmental progress does not jeopardize economic growth. We have added new environmental control requirements, but we have also tried to maintain flexibility in the permitting and review provisions of the bill, so that needed industrial modernization projects do not languish through months or years of permitting delay.

Of necessity, many of these issues have been left to EPA's discretion in implementing the legislation. This is true for such significant issues as the modification/de minimis provisions of section 182(c) (6)-(8) in title I; modification permit procedure provisions in section 112(g)(3); the so-called WEPCo issue in the acid rain title; and the permit flexibility

provision of section 502. We fully anticipate that in addressing these issues after enactment, EPA will recognize the need for flexibility. This is not only a matter of economic importance; it serves important environmental purposes. We have presented industry with a tremendous challenge; we cannot take away from them the tools in terms of modernization and process changes, that will allow them to meet the challenge.

We have been careful to provide this flexibility in each of the title relating to stationary sources:

In title I, we have left the current netting and bubbling provisions unaffected in all but serious, severe and extreme areas. And even in those areas while we have lowered the de minimis threshold to 25 tons, we have tied the de minimis provisions of section 182(c)(6) to the modification provisions of section 182(c) (7) and (8).

In title III, we have included modifications as a separate category for review purposes, thus ensuring that existing sources can modify without triggering new source MACT. Just as importantly, we have structured the modification provisions so that sources need not await lengthy permit revisions or modifications before undertaking plant modifications.

In title IV, we have deleted all general provisions relating to the WEPCO modification issue. We did not in the contemplation that EPA will develop reasonable, revised Wepco regulations that will allow plants to add pollution control equipment, switch to cleaner fuels, and refurbish old facilities without running afoul of NSPS or PSD modifications issues.

In title V, we have explicitly provided permitting authorities with broad discretion to allow plant revisions without requiring permit modifications or revisions.

Mr. Speaker, following President Bush's lead, the final bill includes provisions which will require the use of clean fuels. Cleaner fuels will provide significant environmental benefit without putting even more stringent controls on automobiles. I am particularly pleased by the clean fuels program that struck a balance between oil and gas refiners, farmers, and the environment. The oxygenated fuels program will allow for the use of MTBE and ethanol as additives to achieve the required level of oxygen. The program will result in an increased demand of 600 million gallons of ethanol, creating a market for some 240 million bushels of corn. In turn, increased demand for corn will increase farm income and lower Federal farm program costs.

While title III addresses 189 toxic air pollutants and the control of those pollutants, I wish to focus on the provisions of the utility air toxics study, section 112(n) of the act as added by the conference agreement. With respect to air toxics generally, the Senate and House bills included provisions that differed substantially with respect to scientific studies, timing, and regulatory requirements. The House provision required that the EPA Administrator perform a 3-year study of the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units and report the results of that study to the Congress.

On the other hand, the Senate provision was the result of a complex, and ultimately unsatisfactory, set of negotiations. Unlike the House provision, scientific studies were not to serve as the basis for regulation, but simply were to be included in the docket of the regulatory process leading to regulations. Under the Senate provision, regulations for the control of particulates and mercury would have had to be promulgated no sooner or later than 5 years after enactment.

Rather than accept the Senate provision, the conference favored an approach that adopted the basic House provision. The provision did contain two constructive elements found in the Senate provision; a direction to the National Institute of Environmental Health Sciences to conduct a study on a mercury threshold below which adverse effects on human health are not expected to occur and the requirement that EPA study mercury emissions from all sources. The conferees agreed to the House provisions because of the logic of basing any decision to regulate on the results of scientific study and because of the emission reductions that will be achieved and the extremely high costs that electric utilities will face under other provisions of the new Clean Air Act amendments.

As we all know, the utility industry has been singled out for regulation under the acid rain provisions. The utility industry may also face additional controls for NO_x emissions for ozone control, and revised PM-10 controls. All of these programs will result in substantial reductions in emissions of conventional and potentially hazardous air pollutants. Even without all of these reductions in air pollution, the health risks from emissions of hazardous air pollutants from powerplants are vanishingly small, as EPA has repeatedly recognized.

Under the existing section 112 of the Clean Air Act, EPA has addressed the question whether additional regulation of powerplants is necessary to control air toxic emissions to protect the public health. EPA, thus far, has studied several substances for which emissions data and some indicator of toxicity exist: arsenic, beryllium, cadmium, hexavalent chromium, formaldehyde, and radionuclides. EPA found that additional regulation of emissions of these substances from powerplants was unnecessary. For some other substances listed in S. 1630, such as mercury and other volatile substances, little scientific evidence exists about either emissions rates or effects on public health or welfare. Under the conference agreement adopting the approach that the House included in its bill, these and other scientific issues will be examined, and regulations will be imposed only if warranted by the scientific evidence.

As I noted, the conferees changed only slightly the provision approved by the House. The changes to this provision, and other parts of the bill, clarified the nature of the studies to be conducted on emissions from powerplants and specifically exempted utility units from the provisions of section 112(c)(6), which addresses regulation of seven specified categories of substances.

In addition, section 112(n) provides that the Administrator shall regulate electric utility steam generating units if he finds, based on the studies, that regulation is appropriate and necessary. Under the conference agreement, if the Administrator regulates fossil fuel fired electric utility steam generating units by adopting any major source standard or any area source standard under section 112 for those units, he may do so only in compliance with subsection (n).

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 on the public health. Thus, if the Administrator regulates any of these units, 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 emission reductions--have been demonstrated to cause a significant threat of serious adverse effects on the public health.

In sum, I believe that the conference committee produced a utility air toxics provision that will provide amply protection of the public health while avoiding the imposition of excessive and unnecessary costs on residential, industrial, and commercial consumers of electricity.

My next points are directed at title IV, the acid rain provisions. The conferees have decided to add 200,000 phase I and phase II allowances to the acid rain title, reflecting methodological errors by EPA. These additional allowances are a result of three basic errors that were made in calculating the emission reductions which would occur under the legislation. These mistakes are summarized below.

First, EPA underestimated 1980 utility emissions by failing to use the currently applicable sulfur-to-SO_2 conversion factor during coal combustion. In 1980, EPA assumed that 95 percent of the sulfur was emitted as SO_2, while the balance was retained in bottom ash, rejected in pulverizers, or captured by precipitators. In 1982, EPA revised its "Compilation of Air Pollutant Emission Factors (AP-42)" to indicate it estimated that 97.5 percent of the sulfur in boilers is emitted as SO_2. The 97.5 percent conversion factor was used in the 1985 emissions inventory. Had 97.5 percent been used in 1980, as advocated by NAPAP and DOE, emissions in 1980 would have been at least 180,000 tons higher.

Second, EPA, DOE, and NAPAP underestimated 1980 utility emissions by failing to account for scrubber operability in 1980. Each agency implicitly assumed that at scrubbed units, 31 GW in 1980, the scrubber operated 100 percent of the time that boilers operated, even though contemporaneous EPA contractor reports show that this was not the case. Scrubbers averaged only 80 percent operability in 1980, meaning that 20 percent of the time the boiler operated with uncontrolled emissions. This situation reflected the immaturity of scrubber technology. Had EPA accounted for this fact, EPA's emission estimate would have been 370,000 tons higher than it was.

Third, EPA underestimated 1980 nonutility emissions through reliance on a faulty data base. Using NAPA data--which is supported by DOE, was thoroughly peer reviewed, and conforms to the 1985 NAPAP emissions inventory--it is clear that actual 1980 nonutility emission were 400,000 tons greater in 1980 than EPA has acknowledged.

While these errors in aggregate represent nearly 1 million tons, it was a political decision to limit the size of additional allowance to 200,000 tons. It is important to remember that these extra allowances do not breach the goal set forth in the acid rain title to achieve a 10-million-ton reduction in SO_2 emissions from 1980 levels by the year 2000.

To achieve the most cost-effective SO_2 reductions, the bill contains a market based sulfur dioxide allowance trading system. I wish to address for a moment the importance of this system. If implemented as intended, these provisions can result in savings for electric utility customers while helping attain a substantial reduction of SO_2 by utilities. It has been estimated that 20 to 40 percent of the costs incurred under the traditional command and control approach to regulation, will be saved under the allowance system. The range of savings, however, depends upon the freedom granted utilities to buy and sell allowances. It is essential that we not stifle this new form of market with excessive or variable regulatory controls.

6

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The PRESIDING OFFICER. Without objection, it is so ordered.

(See exhibit 1.) [Exhibit 1 appears on p. 785.]

Mr. BURDICK. Mr. President, we agree that the utilization of a multipollutant control technology should not necessarily include replacement of the boiler to qualify as repowering technology.

Section 402(1) is intended to make clear that technologies eligible for repowering need not necessitate the replacement of the boiler. However, it is intended that all of the criteria are met, that "improvements in efficiency" not necessarily be equivalent to increases in efficiency, and the "multiple combustion emissions" to be controlled extend beyond the acid rain precursors and address other pollutions regulated under the act. Control approaches which string together otherwise separate processes--for instance scrubbers and electrostatic precipitators--should not qualify under the criteria of "controlling multiple combustion emissions simultaneously."

During the Senate consideration of S. 1630, the committee accepted an amendment to the definition of the term "repowering."

The amendment added a set of decision criteria so technologies other than those originally listed could qualify for the phase II time extension. This amendment is intended to encourage innovative technologies that can prevent or otherwise address many combustion pollutants (SO_2, NO_x and trace elements) simultaneously and in an integrated manner.

The intent of adding the criteria was to allow innovative technology, which may or may not require boiler replacement, to qualify if the criteria were met.

The House committee amended H.R. 3030 in a similar manner.

I am pleased the conference report carries this provision, based on the Senate language, and I am confident that new technology will be developed. This is particularly important to me for the future of the lignite coal mining industry in my State.

The conference report includes a number of provisions that will assure that industry and the Government, through the Federal Clean Coal Program, continue to move these technologies into the commercial marketplace as quickly as feasible.

Under section 112(n) utility emissions are exempt from air toxics regulation until studies are completed and the Administrator determines, based on the studies, that air toxics regulation is warranted. The hazardous substance of greatest concern here is mercury. The Senate bill required mercury reductions from coal-fired units. The Senate provision could not be sustained by the scientific facts. What little is known of mercury movement in the biosphere, suggests that its long residence time makes it a long-range transport problem of international or worldwide dimensions. Thus, a full control program in the United States requiring dry scrubbers and baghouses to control mercury emissions from coal-fired power plants would double the costs of acid rain control with no expectation of perceptible improvement in public health in the United States.

I am pleased the conferees adopted the House provision on hazardous air pollutants with respect to utility units.

7

CLEAN AIR ACT, AMENDMENTS

P.L. 101-549, see page 104 Stat. 2399

DATES OF CONSIDERATION AND PASSAGE

Senate : April 3, October 27, 1990
House: May 23, October 26, 1990

Senate Report (Environment and Public Works Committee) No. 101-228, Dec. 20, 1989
[To accompany S. 1630]

House Report (Energy and Commerce Committee) No. 101-490(I), May 17, 1990
[To accompany H.R. 3030]

House Report (Ways and Means Committee) No. 101-490(II), May 21, 1990
[To accompany H.R. 3030]

House Report (Public Works and Transportation Committee) No. 101-490(III), May 21, 1990
[To accompany H.R. 3030]

House Conference Report No. 101-952, Oct. 26, 1990
[To accompany S. 1630]

Cong. Record Vol. 136 (1990)

The Senate bill was passed in lieu of the House bill. The Senate Report (this page) is set out below, and the House Conference Report (page 3867) and the President's Signing Statement (page 3887-1) follow.

SENATE REPORT NO. 101-228

[page iii]

CONTENTS

Section 112 of the Clean Air Act adopted in 1970 requires EPA to list each hazardous air pollutant which is likely to cause an increase in death or serious illness. Within a year after listing EPA is to establish emissions standards which would apply to sources of the listed pollutant "providing an ample margin of safety to protect public health."

In the 18 years of administering section 112, EPA has listed only 8 pollutants: mercury, beryllium, asbestos, vinyl chloride, benezene, radionuclides, inorganic arsenic and coke oven emissions. No standard has been promulgated for coke oven emissions and for many of the other pollutants only a few of the source categories emitting the substance are actually regulated. For instance, mercury is a listed substance, but mercury emissions from powerplant boilers (exempt from standards) are contributing to high mercury levels in the flesh of fish taken in the Great Lakes region.

While EPA has listed only eight substances for regulation, a handful of States with active air toxics programs developed on their own have set standards for 708 substances. In 1983 and upon his return to EPA, William Ruckelshaus committed to make decisions within one year on approximately 25 toxic air pollutants that had been under review since 1977. Subsequently EPA decided that 14 of the substances did not require regulation, that 10 may be listed at some point in the future, and that 1 (coke oven emissions) was to be listed.

In 1985 EPA announced a new air toxics strategy shifting the focus from the regulation of hazardous air pollutants under section 112, to actions under other laws and by the States. The 1985 strategy elevated concern for emissions from the small, area sources like automobiles, dry cleaners, and small combustion units. One action announced in the strategy has been completed—a new source performance standard for wood stoves, but few of the other elements proposed have been implemented.

In 1987 the Court of Appeals for the District of Columbia reviewed decisions made by EPA with respect to vinyl chloride emissions. As with actions on other standards, EPA had considered cost in a decision to withdraw vinyl chloride standards that had been proposed during the later 1970s. The Court found that cost cannot be considered when establishing a safe level of exposure to toxic air pollutants. It is only in determining the margin of safety that EPA is authorized to consider cost and other factors. Because cost had

[page 132]

been considered in several of the other hazardous air pollutant standards established by the Agency, five of the seven standards that had been issued may be reconsidered. The first proposed revisions for radionuclides were issued in the fall of 1989.

Recently, EPA began consideration of a new air toxics strategy that would again shift the focus of the program, this time from in-

dividual polllutants to source categories. The Agency has screened some 900 pollutants and 360 source categories to establish priorities for regulation, identifying 27 source categories as high-priorities for review. But the legal status of such a policy is in doubt, since the current law requires pollutants rather than source categories to be listed and also requires all sources of every listed pollutant to be controlled. Regulation of high priority source categories would necessarily trigger actions on other sources of lower priority hampering the efficiency of a program already short on resources.

Considering this record of false starts and failed opportunities, several conclusions are warranted:

I. Routine and episodic releases of hundreds of noncriteria air pollutants pose a significant threat to public health in the United States.

II. The risk of adverse health effects, principally excess cancers, from exposurse to toxic air pollutants is not distributed evenly across the population. Americans living within the vicinity of concentrated industrial activity or in heavily polluted urban areas may face relatively high risks.

III. Air toxics may also be causing significant environmental damage through deposition and run-off to surface waters, bioaccumulation in the food chain, or disruption of climatic or atmospheric processes.

IV. The Environmental Protection Agency has not made sufficient use of the existing authorities available under section 112 of the Clean Air Act to protect public health.

V. To some extent the statutory language itself may be responsible for the slow pace of the Nation's air toxics program as it requires emissions standards which provide an ample margin of safety to protect public health even for carcinogenic air pollutants where no level of exposure may be considered safe. If interpreted to require standards prohibiting emissions, regulations under section 112 would be potentially very costly for some source categories or pollutants.

VI. The regulatory time frames included in the existing law requiring the proposal of emissions standards within 180 days of listing a pollutant as hazardous and promulgation of standards 180 days later are unrealistic.

VII. A recent court decision nullified basic premises used by the Agency in the standard-setting process for hazardous air pollutants. Although listing and regulatory decisions had been scheduled for several other pollutants in the near-term, this decision is likely to cause additional significant delay as the Agency reassesses its basic policies.

VIII. Some measures proposed by the Agency in its 1985 air toxics strategy offer promise for addressing non-traditional sources of toxic air emissions. However, those proposals are not

currently recognized within the structure of section 112 and have no other statutory authorization.

There is now a broad consensus that the program to regulate hazardous air pollutants under section 112 of the Clean Air Act should be restructured to provide EPA with authority to regulate industrial and area source categories of air pollution (rather than the pollutants) with technology-based standards in the near term.

In light of these conclusions, the reported legislation makes fundamental changes in the basic provisions of section 112 of the Clean Air Act. The bill establishes a list of 191 air pollutants and a mandatory schedule for issuing emissions standards for the major sources of these pollutants. The standards are to be based on the maximum reduction in emissions which can be achieved by application of best available control technology. These new, technology-based standards will become the principal focus of activity under section 112. Authority to issue health-based standards is preserved in modified form to be used for especially serious pollution problems.

This approach to regulation of toxic pollutants is not without precedent. It follows the general model which has been employed since the mid-1970's to control toxic effluents discharged to surface waters by major industrial point sources.

Under the 1972 amendments to the Clean Water Act, industrial dischargers were given two deadlines to control *conventional* pollutants (biological oxygen demand, suspended solids, and acidity): 1) by July 1, 1977 each facility was required to meet emissions limitations reflecting "best practicable control technology currently available" (so-called BPT limits); and 2) by July 1, 1983 each facility was to meet emissions limitations set according to "best available technology economically achievable" (BAT).

Toxic pollutants under the 1972 Act were to be treated differently. The Administrator was to publish a list of toxic pollutants within 90 days and within a year promulgate effluent standards that would provide an "ample margin of safety" to protect the most affected (aquatic) organisms. Thus, the structure of this authority to regulate toxic discharges to surface waters was very similar to the current structure of section 112 of the Clean Air Act.

During the five-year period following passage of the 1972 Clean Water Act, EPA promulgated standards for only six toxic pollutants. In 1975 the Environmental Defense Fund and the Natural Resources Defense Council brought suit against the Agency for failure to list more toxics and to promulgate standards as mandated by the Act. In June 1976, EPA and the plantiffs entered into a consent decree that established a new formula for the development of effluent standards for toxic water pollutants. This agreement created a list of 120 priority pollutants and required EPA to promulgate effluent guidelines based on best available control technology for each pollutant and each industrial category not later than December 31, 1980. Industrial dischargers were to be in compliance with these standards by July 1, 1983, the same deadline as established by the Act for BAT control of conventional pollutants. There were 14,000 dischargers divided into 21 industrial categories and 399 subcategories potentially subject to these new toxics standards.

CERTIFICATE OF SERVICE

I hereby certify that on this 3rd day of August, 2007, two copies of the foregoing Errata were served by first-class mail, postage prepaid to the following persons:

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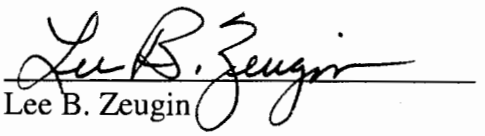
Lee B. Zeugin

provided in the body of a comment will be included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

Use of the *http://www.regulations.gov* Web site to submit comments to EPA electronically is EPA's preferred method for receiving comments. The electronic public docket system is an "anonymous access" system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment. In contrast to EPA's electronic public docket, EPA's electronic mail (e-mail) system is not an "anonymous access" system. If you send an e-mail comment directly to the Docket without going through *http://www.regulations.gov,* your e-mail address is automatically captured and included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket.

Dated: December 23, 2010.

Patricia A. Embrey,

Acting Associate General Counsel.

[FR Doc. 2010–32929 Filed 12–29–10; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9246–1]

Proposed Settlement Agreement, Clean Air Act Citizen Suit

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of Proposed Settlement Agreement; Request for Public Comment.

SUMMARY: In accordance with section 113(g) of the Clean Air Act, as amended ("CAA" or the "Act"), 42 U.S.C. 7413(g), notice is hereby given of a proposed settlement agreement between the following groups of Petitioners: (1) The States of New York, California, Connecticut, Delaware, Maine, New Mexico, Oregon, Rhode Island, Vermont, and Washington, the Commonwealth of Massachusetts, the District of Columbia, and the City of New York (collectively "State Petitioners"); and (2) Natural Resources Defense Council, Sierra Club, and Environmental Defense Fund (collectively "Environmental Petitioners"), and Respondent, the U.S. Environmental Protection Agency ("EPA") (collectively "the Parties"). This proposed settlement is intended to resolve threatened litigation over the EPA's failure to respond to United States Court of Appeals for the District of Columbia Circuit's remand in *State of New York, et al.* v. *EPA,* No. 06–1322. Under the terms of the proposed settlement agreement deadlines have been established for EPA to take action.

DATES: Written comments on the proposed settlement agreements must be received by January 31, 2011.

ADDRESSES: Submit your comments, identified by Docket ID number EPA–HQ–OGC–2010–1057, online at *http://www.regulations.gov* (EPA's preferred method); by e-mail to *oei.docket@epa.gov;* by mail to EPA Docket Center, Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; or by hand delivery or courier to EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC, between 8:30 a.m. and 4:30 p.m. Monday through Friday, excluding legal holidays. Comments on a disk or CD–ROM should be formatted in Word or ASCII file, avoiding the use of special characters and any form of encryption, and may be mailed to the mailing address above.

FOR FURTHER INFORMATION CONTACT: Elliott Zenick, Air and Radiation Law Office (2344A), Office of General Counsel, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; *telephone:* (202) 564–1822; fax number (202) 564–5603; *e-mail address: zenick.elliott@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Additional Information About the Proposed Settlement Agreements

EPA published a final action entitled "Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units," 71 FR 9866 (Feb. 27, 2006) (the "Final Rule"), which included amendments to the standards of performance for electric utility steam generating units subject to 40 CFR part 60, subpart Da ("EGUs") but did not establish standards of performance for greenhouse gas ("GHG") emissions. The State and Environmental Petitioners filed petitions for judicial review of the Final Rule under the CAA Section 111, 42 U.S.C. 7411, contending, *inter alia,* that the Final Rule was required to include standards of performance for GHG emissions from EGUs. The portions of State and Environmental Petitioners' petitions for review of the Final Rule that related to GHG emissions were severed from other petitions for review of the Final Rule, and were formerly pending before the United States Court of Appeals for the District of Columbia Circuit (the "Court") under the caption *State of New York, et al.* v. *EPA,* No. 06–1322. Following the Supreme Court's decision in *Massachusetts* v. *EPA,* 549 U.S. 497 (2007), EPA requested remand of the Final Rule to EPA for further consideration of the issues related to GHG emissions in light of that decision and the Court remanded the Final Rule to EPA for further proceedings. The State Petitioners submitted letters to EPA dated June 16, 2008 and August 4, 2009 inquiring as to the status of EPA's action on the remand and stating their position that EPA had a legal obligation to act promptly to comply with the requirements of Section 111. The Environmental Petitioners submitted a letter to EPA on August 20, 2010 seeking commitments to rulemaking on GHG emissions from EGUs as a means of avoiding further litigation. These letters are included in the docket for this notice.

Under the proposed settlement agreement, EPA will sign by July 26, 2011, and will transmit to the Office of the Federal Register within five business days, a proposed rule under section 111(b) that includes standards of performance for GHGs for new and modified EGUs that are subject to 40 CFR part 60, subpart Da. EPA will also sign by July 26, 2011, and will transmit to the Office of the Federal Register within five business days, a proposed rule under section 111(d) that includes emissions guidelines for GHGs from existing EGUs that would have been subject to 40 CFR part 60, subpart Da if they were new sources. Under the proposed settlement agreement EPA will take final action with respect to the proposed rule no later than May 26, 2012. The proposed settlement agreement provides that EPA's fulfillment of its obligations under the agreement shall result in a full and final release of any claims that State and Environmental Petitioners may have under any provision of law to compel EPA to respond to the Court's Remand Order with respect to GHG emissions from EGUs.

For a period of thirty (30) days following the date of publication of this notice, the Agency will accept written comments relating to the proposed settlement agreement from persons who were not named as parties or intervenors to the litigation in question. EPA or the Department of Justice may

withdraw or withhold consent to the proposed settlement agreement if the comments disclose facts or considerations that indicate that such consent is inappropriate, improper, inadequate, or inconsistent with the requirements of the Act. Unless EPA or the Department of Justice determines that consent to this settlement agreement should be withdrawn, the terms of the agreement will be affirmed.

II. Additional Information About Commenting on the Proposed Settlement Agreement

A. How can I get a copy of the settlement agreement?

The official public docket for this action (identified by Docket ID No. EPA–HQ–OGC–2010–1057) contains a copy of the proposed settlement agreement. The official public docket is available for public viewing at the Office of Environmental Information (OEI) Docket in the EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OEI Docket is (202) 566–1752.

An electronic version of the public docket is available through *http://www.regulations.gov.* You may use *http://www.regulations.gov* to submit or view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Once in the system, key in the appropriate docket identification number then select "search".

It is important to note that EPA's policy is that public comments, whether submitted electronically or on paper, will be made available for public viewing online at *http://www.regulations.gov* without change, unless the comment contains copyrighted material, CBI, or other information whose disclosure is restricted by statute. Information claimed as CBI and other information whose disclosure is restricted by statute is not included in the official public docket or in the electronic public docket. EPA's policy is that copyrighted material, including copyrighted material contained in a public comment, will not be placed in EPA's electronic public docket but will be available only in printed, paper form in the official public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the EPA Docket Center.

B. How and to whom do I submit comments?

You may submit comments as provided in the **ADDRESSES** section. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked "late." EPA is not required to consider these late comments.

If you submit an electronic comment, EPA recommends that you include your name, mailing address, and an e-mail address or other contact information in the body of your comment and with any disk or CD–ROM you submit. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. Any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

Use of the *http://www.regulations.gov* Web site to submit comments to EPA electronically is EPA's preferred method for receiving comments. The electronic public docket system is an "anonymous access" system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment. In contrast to EPA's electronic public docket, EPA's electronic mail (e-mail) system is not an "anonymous access" system. If you send an e-mail comment directly to the Docket without going through *http://www.regulations.gov,* your e-mail address is automatically captured and included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket.

Dated: December 23, 2010.

Patricia A. Embrey,

Acting Associate General Counsel.

[FR Doc. 2010–32935 Filed 12–29–10; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Submitted for Review and Approval to the Office of Management and Budget (OMB), Comments Requested

December 21, 2010.

SUMMARY: As part of its continuing effort to reduce paperwork burden and as required by the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3501–3520), the Federal Communications Commission invites the general public and other Federal agencies to comment on the following information collection. Comments are requested concerning: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; (b) the accuracy of the Commission's burden estimate; (c) ways to enhance the quality, utility, and clarity of the information collected; (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology; and (e) ways to further reduce the information collection burden for small business concerns with fewer than 25 employees.

The FCC may not conduct or sponsor a collection of information unless it displays a currently valid OMB control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act (PRA) that does not display a valid OMB control number.

DATES: Written Paperwork Reduction Act (PRA) comments should be submitted on or before January 31, 2011. If you anticipate that you will be submitting PRA comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the FCC contact listed below as soon as possible.

ADDRESSES: Direct all PRA comments to Nicholas A. Fraser, Office of Management and Budget, via fax at 202–395–5167 or the Internet at *Nicholas_A._Fraser@omb.eop.gov;* and to *the* Federal Communications Commission's PRA mailbox (*e-mail address: PRA@fcc.gov.*). Include in the e-mail the OMB control number of the collection as shown in the **SUPPLEMENTARY INFORMATION** section below, or if there is no OMB control number, include the Title as shown in the **SUPPLEMENTARY INFORMATION** section.

FEDERAL REGISTER

Vol. 77 Friday,
No. 72 April 13, 2012

Part II

Environmental Protection Agency

40 CFR Part 60
Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources; Electric Utility Generating Units; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2011–0660; FRL–9654–7]

RIN 2060–AQ91

Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The United States EPA is proposing new source performance standards for emissions of carbon dioxide (CO_2) for new affected fossil fuel-fired electric utility generating units (EGUs). The EPA is proposing these requirements because CO_2 is a greenhouse gas (GHG) and fossil fuel-fired power plants are the country's largest stationary source emitters of GHGs. The EPA in 2009 found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations. The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGUs greater than 25 megawatt electric (MWe) to meet an output-based standard of 1,000 pounds of CO_2 per megawatt-hour (lb CO_2/MWh), based on the performance of widely used natural gas combined cycle (NGCC) technology. Because of the economics of the energy sector, the EPA and others project that NGCC will be the predominant choice for new fossil fuel-fired generation even absent this rule. In its base case analysis, the EPA does not project any new coal-fired EGUs without CCS to be built in the absence of this proposal through 2030. New coal-fired or pet coke-fired units could meet the standard either by employing carbon capture and storage (CCS) [1] of approximately 50% of the CO_2 in the exhaust gas at startup, or through later application of more effective CCS to meet the standard on average over a 30-year period. The 30-year averaging option could also provide flexibility for owners and operators of coal or pet coke units implementing CCS at the outset of the unit's operation that were designed and operated to emit at less than 1,000 lb CO_2/MWh to address startup concerns or short term interruptions in their ability to sequester captured carbon dioxide. The EPA is not proposing standards of performance for existing EGUs whose CO_2 emissions increase as a result of installation of pollution controls for conventional pollutants, or for proposed EGUs, which are referred to here as transitional sources, that have acquired a complete preconstruction permit by the time of this proposal and that commence construction within 12 months of this proposal. As a result, those sources would not be subject to the standards of performance proposed in today's rule.

DATES: *Comments.* Comments must be received on or before June 12, 2012. Under the Paperwork Reduction Act (PRA), since the Office of Management and Budget (OMB) is required to make a decision concerning the information collection request between 30 and 60 days after April 13, 2012, a comment to the OMB is best assured of having its full effect if the OMB receives it by May 14, 2012.

Public Hearing. The EPA will hold public hearings on this proposal. The dates, times, and locations of the public hearings will be announced separately. Oral testimony will be limited to 5 minutes per commenter. The EPA encourages commenters to provide written versions of their oral testimonies either electronically or in paper copy. Verbatim transcripts and written statements will be included in the rulemaking docket. If you would like to present oral testimony at one of the hearings, please notify Ms. Pamela Garrett, Sectors Policies and Programs Division (C504–03), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–7966; email: *garrett.pamela@epa.gov.* Persons wishing to provide testimony should notify Ms. Garrett at least 2 days in advance of the public hearings. The public hearings will provide interested parties the opportunity to present data, views, or arguments concerning the proposed rule. The EPA officials may ask clarifying questions during the oral presentations, but will not respond to the presentations or comments at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearing. For updates and additional information on the public hearings, please check the EPA's Web site for this rulemaking, *http://www.epa.gov/airquality/carbonpollutionstandards.*

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2011–0660, by one of the following methods:

At the Web site http://www.regulations.gov: Follow the instructions for submitting comments.

At the Web site http://www.epa.gov/oar/docket.html: Follow the instructions for submitting comments on the EPA Air and Radiation Docket web site.

Email: Send your comments by electronic mail (email) to *a-and-r-docket@epa.gov,* Attn: Docket ID No. EPA–HQ–OAR–2011–0660.

Facsimile: Fax your comments to (202) 566–9744, Attn: Docket ID No. EPA–HQ–OAR–2011–0660.

Mail: Send your comments to the EPA Docket Center, U.S. EPA, Mail Code 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Attn: Docket ID No. EPA–HQ–OAR–2011–0660. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for EPA, 725 17th St. NW., Washington, DC 20503.

Hand Delivery or Courier: Deliver your comments to the EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave., NW., Room 3334, Washington, DC, 20460, Attn: Docket ID No. EPA–HQ–OAR–2011–0660. Such deliveries are accepted only during the Docket's normal hours of operation (8:30 a.m. to 4:20 p.m., Monday through Friday, excluding legal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include agency name and docket ID number (EPA–HQ–OAR–2011–0660). The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–

[1] Throughout this preamble, we refer to 'carbon capture and storage' or CCS. By this, we mean the use of a technology for separating and capturing CO_2 from the flue gas or syngas stream with subsequent compression and transportation to a suitable location for long term storage and monitoring. Many references refer to CCS as 'carbon capture and sequestration'. In this preamble, 'storage' and 'sequestration' mean the same thing and the words are used interchangeably.

HQ–OAR–2011–0660. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

The EPA requests that a separate copy of your comments also be sent to the contact person identified below (see **FOR FURTHER INFORMATION CONTACT**). If the comment includes information you consider to be CBI or otherwise protected, a copy of the comment that does not contain the information claimed as CBI or otherwise protected should be sent.

The *www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *http://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (e.g., CBI or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742. Visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm* for additional information about the EPA's public docket.

In addition to being available in the docket, an electronic copy of this proposed rule will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the proposed rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/.* The TTN provides information and technology exchange in various areas of air pollution control.

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–4003, facsimile number (919) 541–5450; email address: *fellner.christian@epa.gov* or Dr. Nick Hutson, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–2968, facsimile number (919) 541–5450; email address: *hutson.nick@epa.gov.*

SUPPLEMENTARY INFORMATION: *Acronyms.* A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined as follows:

AB Assembly Bill
AEP American Electric Power
AEO Annual Energy Outlook
ANSI American National Standards Institute
ASME American Society of Mechanical Engineers
ASTM American Society for Testing of Materials
BACT Best Available Control Technology
BDT Best Demonstrated Technology
BSER Best System of Emission Reduction
Btu/kWh British Thermal Units per Kilowatt Hour
Btu/lb British Thermal Units per Pound
CAA Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting
CEMS Continuous Emissions Monitoring System
CH_4 Methane
CHP Combined Heat and Power
CO_2 Carbon Dioxide
CSAPR Cross-State Air Pollution Rule
DOE Department of Energy
DOT Department of Transportation
ECMPS Emissions Collection and Monitoring Plan System
EERS Energy Efficiency Resource Standards
EGU Electric Utility Generating Units
EIA Energy Information Administration
EO Executive Order
EOR Enhanced Oil Recovery
EPA Environmental Protection Agency
FR Federal Register
GHG Greenhouse Gas
H_2 Hydrogen Gas
HAP Hazardous Air Pollutant
HFC Hydrofluorocarbon
HRSG Heat Recovery Steam Generator
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
IPM Integrated Planning Model
kg/MWh Kilogram per Megawatt-hour
kJ/kg Kilojoules per Kilogram
kWh Kilowatt Hour
lb CO_2/MMBtu Pound of CO_2 per Million British Thermal Unit
lb CO_2/MWh Pound of CO_2 per Megawatt-hour
lb CO_2/yr Pound of CO_2 per Year
lb/lb-mole Pound per Pound-Mole
MATS Mercury and Air Toxic Standards
MW Megawatt
MWe Megawatt Electric
MWh Megawatt-hour
N_2O Nitrous Oxide
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NAS National Academy of Sciences
NETL National Energy Technology Laboratory
NGCC Natural Gas Combined Cycle
NRC National Research Council
NSPS New Source Performance Standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
O_2 Oxygen Gas
OMB Office of Management and Budget
PC Pulverized Coal
PFC Perfluorocarbon
PM Particulate Matter
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
RCRA Resource Conservation and Recovery Act
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory Impact Analysis
RPS Renewable Portfolio Standard
SBA Small Business Administration
SCC Social Cost of Carbon
SCR Selective Catalytic Reduction
SF_6 Sulfur Hexafluoride
SIP State Implementation Plan
SNCR Selective Non-Catalytic Reduction

SO_2 Sulfur Dioxide
SSM Startup, Shutdown, and Malfunction
Tg Teragram
Tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UIC Underground Injection Control
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USGCRP U.S. Global Climate Research Program
VCS Voluntary Consensus Standard
WWW Worldwide Web

Organization of This Document. The information presented in this preamble is organized as follows:

I. General Information

A. Summary

1. Executive Summary

In this rulemaking, the EPA proposes to limit GHG emissions from new fossil fuel-fired power plants by limiting CO_2 emissions. The proposed rule is undertaken pursuant to section 111 of the Clean Air Act, which establishes a several step process for the EPA and the States to regulate air pollutants from stationary sources. Under section 111, the EPA must regulate emissions from new sources in the source category by issuing a standard of performance, which is defined as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account * * * cost [and other factors]) * * * has been adequately demonstrated.''

In today's action, the EPA is proposing to combine electric utility steam generating units (boilers and IGCC units, which are currently included in the Da category) and combined cycle units that generate electricity for sale and meet certain size criteria (which are currently included in the KKKK category), into a new category for new sources (the TTTT category) for the purposes of GHG emissions. The EPA is proposing standards of performance that require that all new fossil fuel-fired EGUs meet an electricity-output-based emission rate of 1,000 lb CO_2/MWh of electricity generated on a gross basis. This proposed standard is based on the demonstrated performance of natural gas combined cycle (NGCC) units, which are currently in wide use throughout the country, and are likely to be the predominant fossil fuel-fired technology for new generation in the future.

New coal-, coal refuse-, oil- and petroleum coke-fired boilers and IGCC units should also be able to meet this standard by employing carbon capture and storage (CCS) technology. While a coal unit with CCS may be more expensive to construct than NGCC generation, for reasons explained below, we expect the difference to decrease over time as CCS becomes more mature and less expensive.

We include in today's proposed rulemaking a 30-year averaging compliance option under which affected coal- and pet coke-fired sources could comply with the 1,000 lb CO_2/MWh standard on a 30-year average basis. Coal- and pet coke-fired EGUs that use this compliance alternative must meet an immediate performance standard of 1,800 lb CO_2/MWh (gross) on a 12-month annual average basis, which can be achieved by a ''supercritical'' efficiency level, during the period before installation of CCS. By no later than the beginning of the 11th year, the facility would be required to meet a reduced CO_2 emission limit of no more than 600 lb CO_2/MWh (gross) on a 12-month annual average basis for the remaining 20 years of the 30-year period, such that the weighted average CO_2 emissions rate from the facility over the 30-year time period would be equivalent to the proposed standard of performance of 1,000 lb CO_2/MWh.

Today's proposal to require an emission rate of 1,000 lb CO_2/MWh meets the requirements for a ''standard of performance,'' as defined under CAA section 111(a)(1). This proposed standard is based on the degree of emission limitation achievable through natural gas combined cycle generation. NGCC qualifies as the ''best system of emission reduction'' (BSER) that the EPA has determined has been adequately demonstrated. New natural gas-fired EGUs are less costly than new coal-fired EGUs, and as a result, our Integrated Planning Model (IPM) model projects that for economic reasons, natural gas-fired EGUs will be the facilities of choice until at least 2020, which is the analysis period for this rulemaking.

Indeed, our IPM model does not project construction of any new coal-fired EGUs during that period. This state of affairs has come about primarily because technological developments and discoveries of abundant natural gas reserves have caused natural gas prices to decline precipitously in recent years and have secured those relatively low prices for the near-future. We emphasize that, in light of a number of economic factors, including the increased availability and significantly lower price

of natural gas, energy industry modeling forecasts uniformly predict that few, if any, new coal-fired power plants will be built in the foreseeable future.

We recognize that some owners/operators may nevertheless seek to construct new coal-fired capacity. This may be beneficial from the standpoint of promoting energy diversity, and today's proposal does not interfere with construction of new coal-fired capacity. At present, while CCS would add considerably to the costs of a new coal-fired power plant, there are sources of funding available to support the deployment of CCS, including a limited number of government demonstration programs. Even if companies decide to construct a few new coal-fired power plants under any circumstance, those few may well have access to those government programs. We expect that the costs of CCS will decline in the future as CCS matures and is utilized more widely.

For purposes of today's action, the EPA does not have a sufficient base of information to develop a proposal for the anticipated relatively few affected sources that may be expected to take actions that would constitute ''modifications'' (as defined under the EPA's NSPS regulations) and therefore be subject to requirements for new sources. As a result, the EPA is not proposing requirements for NSPS modifications.

The EPA is aware that approximately 15 proposed EGUs have received CAA permitting authority approval for their preconstruction permits, but may not have ''commenced construction'' by the date of today's proposed rulemaking. For this proposed rule, these sources that, as of the date of this proposal, have a PSD permit and are poised to commence construction within the very near future are referred to as ''transitional sources.'' In today's proposed rulemaking, the EPA is not proposing a standard of performance for transitional sources, which we define as sources that have been issued a PSD permit by the date of proposal (including sources that have approved permits that are in the process of being amended, if those sources are intending to install CCS as evidenced by participating in any of the DOE CCS funding programs, either loan guarantee or grant programs) and that commence construction within 12 months of the date of publication of this proposal in the **Federal Register**. Upon finalization of this rulemaking without a standard of performance applicable to these sources, they will not be treated as new sources subject to the specific limitations set forth in the final new source standards.

Our IPM modeling, using Energy Information Administration (EIA) reference case assumptions, projects that there will be no construction of new coal-fired generation without CCS by 2030. Under these assumptions, the proposed rule will not impose costs by 2030. We also examined a scenario with both increased future natural gas prices and increased future electric demand. In this sensitivity case, we saw small amounts of coal-fired generation being built in 2030. Even under this sensitivity analysis with small amounts of new coal generation under conditions of high natural gas prices and simultaneously high electricity demand in 2030, we do not project that this proposed rule will impose notable costs upon sources.

We seek comments on all aspects of this proposal and identify a number of aspects of the proposal on which comments are specifically requested.

B. Overview and Outline

1. Overview

In this rulemaking, the EPA proposes to limit GHG emissions from new fossil fuel-fired power plants by limiting CO_2 emissions. In 2009, the EPA issued a finding that GHG air pollution may reasonably be anticipated to endanger Americans' public health and welfare, now and in the future, by contributing to climate change. Fossil fuel-fired power plants emit more GHG emissions than any other stationary source category in the United States, and among new GHG emissions sources, the largest individual sources are in this source category. This rulemaking proposes federal standards of performance for new fossil fuel-fired power plants that can be met with existing technology.

Note that in this preamble, while we refer to these sources, interchangeably, as power plants, steam generating units, affected sources, fossil fuel-fired electric generating units, covered EGUs, or, simply, EGUs, the proposed standards apply to only those sources identified in Section III.A. as the affected source category.

2. Why is the EPA proposing this rule?

This proposed rule reflects the EPA's common-sense approach to reducing CO_2 and other GHG emissions, which by causing climate change, pose a serious threat to public health and welfare. The EPA is focusing first on reducing emissions from the largest emitters through measures with reasonable costs. The EPA is proposing to control CO_2 pollution from fossil fuel-fired power plants because they are responsible for approximately 40 percent of all U.S. anthropogenic CO_2 emissions.[2] Individual new coal-fired power plants are among the largest individual new sources of GHGs. Furthermore, design and technology choices, such as NGCC, exist that can be readily and cost-effectively used to reduce GHG emissions from new fossil fuel-fired power plants. Thus, this proposed rule is a rational first step to control GHG emissions from the largest-emitting stationary sources under CAA section 111.

a. The Serious Threat of Climate Change to the Public's Health and Welfare. Climate change, including global warming, is a significant threat to the global environment. The National Research Council (NRC) of the National Academies[3] stated in a 2011 report, ''Each additional ton of greenhouse gases emitted commits us to further change and greater risks. In the judgment of the [NRC] Committee on America's Climate Choices, the environmental, economic, and humanitarian risks of climate change indicate a pressing need for substantial action to limit the magnitude of climate change and to prepare to adapt to its impacts.''[4]

Action to reduce emissions is warranted because, as the EPA stated in its 2009 Endangerment Finding,[5] GHGs endanger the public health and public welfare of current and future generations. The anthropogenic buildup of GHGs in the atmosphere is very likely (90 to 99 percent probability) the cause of most of the observed global warming over the last 50 years.[6] Based on the Endangerment Finding and its underlying technical support document (TSD),[7] reasons to reduce GHG emissions include the following:

[2] Or 32.4% of all anthropogenic GHG emissions; from information in Table 2–1 from 'Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009,' U.S. Environmental Protection Agency, EPA 430–R–11–005, April 2011.

[3] The National Academies comprise the National Academy of Sciences, National Academy of Engineering, Institute of Medicine and National Research Council.

[4] National Research Council (2011) *America's Climate Choices,* Committee on America's Climate Choices, Board on Atmospheric Sciences and Climate, Division on Earth and Life Studies, The National Academies Press, Washington, DC.

[5] EPA, ''Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act'' (74 FR 66,496; Dec. 15, 2009). *http://epa.gov/climatechange/endangerment.html.*

[6] Endangerment Finding at 74 FR 66,518, which notes that the 2007 conclusion of the Intergovernmental Panel on Climate Change was re-confirmed by the June 2009 assessment by the U.S. Global Change Research Program.

[7] EPA, ''Technical Support Document for Endangerment and Cause or Contribute Findings for

Continued

• The key effects of climate change observed to date and projected to occur in the future include, but are not limited to, more frequent and intense heat waves, more severe wildfires, degraded air quality, heavier and more frequent downpours and flooding, increased drought, greater sea level rise and storm surge, more intense storms, harm to water resources, continued ocean acidification, harm to agriculture, and harm to wildlife and ecosystems.

• These effects are anticipated to result in premature deaths, illnesses, damage to property and infrastructure, and other harm to people's welfare in the U.S.

• Those ''most vulnerable'' to climate related health effects, such as children, the elderly and the poor—and future generations—face disproportionate risks.[8]

• Human-induced climate change impacts have the potential to be far-reaching and multidimensional, though not all risks and potential impacts can be quantified.[9]

• A supporting consideration is that climate change impacts in certain regions of the world (potentially leading, for example, to food scarcity, conflicts or mass migration) may exacerbate problems that raise humanitarian, trade and national security issues for the United States.[10]

The TSD further notes that some risks, such as the extinction of many species, would be irreversible.[11] Also, the TSD points to research on the potential for ''abrupt changes'' [12] which have uncertain or low probability but high potential impact. The NRC has said abrupt changes are an important consideration because, if triggered, they could occur so quickly and unexpectedly that human or natural systems would have difficulty adapting to them.[13] Examples include severe drought in subtropical areas, release of large amounts of GHGs stored in the sea floor and frozen Arctic soils, and rapid disintegration of Greenland ice sheet or collapse of the West Antarctic ice sheet leading to many feet of sea level rise.[14]

The special characteristics of GHGs make it important to take initial steps to control the largest emissions categories without delay. Unlike most traditional air pollutants, GHGs persist in the atmosphere for time periods ranging from decades to millennia, depending on the greenhouse gas. Greenhouse gases will continue to accumulate in the atmosphere at higher and higher concentrations each year unless substantial reductions in global greenhouse gas emissions are achieved. The NRC notes that emissions reduction choices made today matter in determining the level of impacts experienced not just over the next few decades, but in the coming centuries and millennia.[15] Also, the longer that the U.S. and other countries take to reduce emissions, the greater the future emissions reductions that will be required to limit global temperature increase to any given level.

This proposed rule to limit GHG emissions from the largest U.S. stationary source category will contribute to the emissions reductions required to slow or reverse the accumulation of GHG concentrations in the atmosphere, which is necessary to protect against projected climate change impacts and risks. Reducing GHG emissions reduces the impacts and risks articulated in the Endangerment Finding and TSD.

b. The High Level of GHG Emissions from Fossil-Fuel-Fired Power Plants and the Opportunities to Reduce these Emissions. Fossil fuel-fired power plants comprise the largest category of stationary source GHG emissions in the U.S. These sources account for approximately 40 percent of total U.S. anthropogenic CO_2 emissions, based on 2009 data.[16] Among all stationary sources of GHG emissions, fossil-fuel-fired power plants generally constitute the largest individual sources.

Furthermore, a range of options are available to reduce emissions of new power plants. For economic reasons, most new power plants being built in the U.S. today are either natural gas-fired or are powered by renewable sources of energy, such as wind and solar, and therefore generally produce significantly fewer CO_2 emissions than uncontrolled coal-fired power plants. Natural gas combustion inherently emits less CO_2 than coal combustion and the technology of choice for generating electricity with natural gas, stationary combined cycle gas turbines, is also more efficient. Almost all the stationary combined cycle gas turbines built in the U.S. in the last five years can meet the proposed standard of 1,000 lb CO_2/MWh. New coal-fired power plants can install CCS technology and can thereby limit their CO_2 emissions per MWh generated to levels similar to, or even lower than, those of natural gas-fired combined cycle plants without CCS. New coal-fired power plants with CCS are being permitted and built today, albeit usually with considerable financial assistance from the federal government.

c. Alignment with Industry's Other CAA Obligations. Establishing the overall regulatory requirements for GHG emissions from new fossil fuel-fired power plants at this time is efficient because the EPA has recently issued regulations to limit criteria and hazardous air pollutants from these sources. Aligning the timing of these GHG rules with the rules for criteria and air toxics pollutants gives the industry more regulatory certainty, will facilitate the industry's investment decisions, and will help inform its compliance decisions to meet all of its CAA obligations.

d. Promotion of Energy Diversity. This proposed rule is consistent with the President's goal to ensure that ''by 2035 we will generate 80% of our electricity from a diverse set of clean energy sources—including renewable energy sources like wind, solar, biomass and hydropower, nuclear power, efficient natural gas and clean coal.'' [17] The proposed rule will assist the deployment of CCS technology for new coal-fired power plants and reinforce incentives for the use of efficient natural gas-fired generation. Regulatory uncertainty may be hindering the development and deployment of CCS, as evidenced by American Electric Power (AEP)'s recent deferral of a large-scale CCS retrofit demonstration project on one of its coal-fired power plants because the State's utility regulators would not approve CCS without a

Greenhouse Gases under Section 202(a) of the Clean Air Act, Dec. 9, 2009.'' Both the **Federal Register** Notice and the TSD for Endangerment and Cause or Contribute Findings are found in the public docket established for the endangerment rulemaking, Docket No. EPA–OAR–2009–0171 and at *http://epa.gov/climatechange/endangerment.html.*

[8] Endangerment Finding, 74 FR 66498.

[9] Endangerment Finding, 74 66497.

[10] Endangerment Finding, 74 FR 66535.

[11] Endangerment TSD, p. 136.

[12] Endangerment TSD, p. 75–78. The U.S. Climate Change Science Program defined ''abrupt change'' as a ''large-scale change in the climate system that takes place over a few decades or less, persists (or is anticipated to persist) for at least a few decades, and causes substantial disruptions in human and natural systems.'' Synthesis and Assessment Product (SAP) 3.4: Abrupt Climate Change (2008).

[13] Endangerment TSD, p. 75, citing National Research Council (2002).

[14] Endangerment TSD, pp. 76–78.

[15] National Research Council (NRC) (2011). Climate Stabilization Targets. Committee on Stabilization Targets for Atmospheric Greenhouse Gas Concentrations; Board on Atmospheric Sciences and Climate, Division of Earth and Life Sciences, National Academy Press. Washington, DC.

[16] Or 32.4% of all anthropogenic GHG emissions; from information in Table 2–1 from 'Inventory of U. S. Greenhouse Gas Emissions and Sinks: 1990—2009', U. S. Environmental Protection Agency, EPA 430–R–11–005, April 2011.

[17] ''Blueprint for a Secure Energy Future'', March 30, 2011.

regulatory requirement to reduce CO_2.[18] The standard established in this proposal would help create the regulatory certainty that CCS is the path forward for new coal-fired generation.

3. Legal Proceedings Leading up to This Rulemaking

In April 2007, the U.S. Supreme Court ruled, in *Massachusetts* v. *EPA,*[19] that GHGs meet the definition of ''air pollutant'' in the CAA. This decision clarified that the authorities and requirements of the CAA, including section 111, apply to GHG emissions.

As a result of this decision, the EPA obtained a voluntary remand from the U.S. Court of Appeals for the District of Columbia Circuit (the ''Court'') to reconsider the EPA's actions in a 2006 rulemaking for EGUs under CAA section 111, in which the EPA had promulgated standards for criteria air pollutants, but had declined to regulate GHG emissions. In part in response to threatened litigation over the EPA's failure to act on the remand, the EPA agreed to propose today's action to regulate GHG emissions from new fossil fuel-fired EGUs.

4. Legal Basis for CAA Standards for Fossil-Fired Power Plants

a. General Legal Requirements. Clean Air Act section 111 establishes a several step process for the EPA and the States to regulate air pollutants from stationary sources. First, the EPA must list categories of stationary sources that cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Then, the EPA must regulate emissions from new sources in the source category by issuing a standard of performance, which is defined as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account * * * cost [and other factors]) * * * has been adequately demonstrated.'' New sources include new construction, and, as discussed below, modifications to existing sources as well as reconstructed sources. Standards of performance for new sources are often referred to as new source performance standards (NSPS).

b. Cause-or-Contribute-Significantly Finding for Fossil Fuel-Fired Power Plants and Endangerment Finding for GHG Air Pollution. The EPA is authorized to regulate GHGs from power plants based on earlier actions concerning endangerment. Before today's rulemaking, the EPA listed different types of fossil fuel-fired EGUs as source categories that caused or contributed significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. Specifically, the EPA listed electric utility steam generating boilers, including coal-fired boilers, and initially regulated them in subpart D of its regulations under CAA section 111. Subsequent regulation of utility boilers has been under subpart Da. The EPA listed stationary combustion turbine engines and initially regulated them under subpart GG. The stationary combustion turbine engine portions of combined cycle facilities were also regulated under subpart GG. Heat recovery steam generators (HRSG) associated with combined cycle facilities with duct burners were regulated under either subpart Da or one of the industrial boiler regulations, depending on the specific characteristics of the HRSG. To minimize the compliance burden for owners/operators of combined cycle facilities some monitoring harmonization was done, but the two subparts were still applicable. In 2005, the EPA proposed subpart KKKK as a replacement for subpart GG and specifically covered the entire combined cycle facility under subpart KKKK such that only a single set of requirements would apply. In that same year, the EPA proposed to include Integrated Gasification Combined Cycle (IGCC) facilities under the applicability of subpart Da. The EPA is authorized to promulgate the rulemaking proposed today—which would establish standards of performance for CO_2 emissions from EGUs currently in the Da and KKKK source categories—because the EPA has already determined that both those source categories cause or contribute significantly to air pollution that may reasonably be expected to endanger public health or welfare. Clean Air Act section 111 does not require the EPA, as a prerequisite to regulating any particular air pollutant, to issue an endangerment finding or a cause-or-contribute-significantly finding for that air pollutant from that source category.

As an alternative, the EPA is considering whether CAA section 111 should be interpreted to require that the EPA base its regulation of CO_2 emissions from EGUs on two findings: (i) A finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare; and (ii) a finding that CO_2 emissions from EGUs cause or contribute significantly to that air pollution. If section 111 were so interpreted, the EPA believes that (a) the 2009 Endangerment Finding, along with the EPA's 2010 action denying petitions to reconsider that finding (which action reviewed scientific developments after the Endangerment Finding) would fulfill any requirement to make the endangerment finding concerning GHG air pollution; and (b) the large amount of CO_2 emissions from EGUs clearly exceeds the low applicability threshold upon which the EPA would make the cause-or-contribute-significantly finding.

As another alternative, the EPA is also considering whether CAA section 111 should be interpreted to require that the EPA base its regulation of CO_2 emissions from EGUs on a rational basis for protection of the public health or welfare. If section 111 were so interpreted, the EPA believes that (i) its 2009 Endangerment Finding and 2010 denial of petitions to reconsider, by themselves, and particularly in conjunction with the National Academy of Sciences' assessment reports issued since then, coupled with (ii) the fact that EGUs are the largest stationary source emitters of CO_2, provide a rational basis for regulating CO_2 emissions from EGUs. There is no reason to revisit the 2009 Endangerment Finding given recent scientific findings that strengthen the scientific conclusion that GHG air pollution endangers public health and welfare.[20]

5. Summary of Today's Proposed Requirements To Reduce GHG Emissions From New Fossil Fired Power Plants, and Rationale for Those Requirements

a. Summary of Proposed Revisions to Categories and Requirements for New Sources

i. Revisions to Categories of EGUs. In today's action, the EPA is proposing to

[18] In a July 17, 2011, press release, AEP's chairman said, ''We are placing the project on hold until economic and policy conditions create a viable path forward * * * We are clearly in a classic 'which comes first?' situation. The commercialization of this technology is vital if owners of coal-fueled generation are to comply with potential future climate regulations without prematurely retiring efficient, cost-effective generating capacity. But as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share.''

[19] 549 U.S. 497 (2007).

[20] These recent scientific findings are described in section II of this notice, titled ''Background.'' See subsection II.B.3., ''Climate Impacts Detailed in Recent NRC Assessments.'' The legal options introduced here are presented in detail below in section IV.A.2, ''Endangerment and Cause-or-Contribute-Significantly Finding.''

combine electric utility steam generating units (boilers and IGCC units, which are currently included in the Da category) and combined cycle units that generate electricity for sale and meet certain size criteria (which are currently included in the KKKK category), into a new category for new sources (the TTTT category) for the purposes of GHG emissions. Today's proposed rulemaking would not affect NSPS requirements for criteria air pollutants, simple cycle turbines or EGUs located in non-continental areas.[21] It also would not affect biomass-fired boilers (including those that sell electricity to the grid) that co-fire with less than 250 MMBtu/h of any fossil fuel (biomass boilers currently subject to subpart Db, the Industrial-Commercial-Institutional Steam Generating Unit NSPS).

ii. Control Requirements for New Sources. The EPA is proposing standards of performance that require that all new fossil fuel-fired EGUs meet an electricity-output-based emission rate of 1,000 lb CO_2/MWh of electricity generated on a gross basis. This proposed standard is based on the demonstrated performance of natural gas combined cycle (NGCC) units, which are currently in wide use throughout the country, and are likely to be the predominant fossil fuel-fired technology for new generation in the future.

New coal-, coal refuse-, oil- and petroleum coke-fired boilers and IGCC units should also be able to meet this standard by employing CCS technology. There are currently a number of coal- and pet coke-fired EGU projects under development that include CCS. While a coal unit with CCS may be more expensive to construct than NGCC generation, for reasons explained below, we expect the difference to decrease over time as CCS becomes more mature and less expensive.

We include in today's proposed rulemaking a 30-year averaging compliance option under which affected coal- and pet coke-fired sources could comply with the 1,000 lb CO_2/MWh standard on a 30-year average basis. Coal- and pet coke-fired EGUs that use this compliance alternative must meet an immediate performance standard of 1,800 lb CO_2/MWh (gross) on a 12-month annual average basis, which can be achieved by a ''supercritical'' efficiency level, during the period before installation of CCS. By no later than the beginning of the 11th year, the facility would be required to meet a reduced CO_2 emission limit of no more than 600 lb CO_2/MWh (gross) on a 12-month annual average basis for the remaining 20 years of the 30-year period, such that the weighted average CO_2 emissions rate from the facility over the 30-year time period would be equivalent to the proposed standard of performance of 1,000 lb CO_2/MWh.

We seek comment on this compliance option and on reasonable variations on the framework we propose to establish, and in particular on a mechanism for establishing practicably enforceable short term limits during the 30-year period. The potential approaches here include (1) requiring the owner/operator to identify and obtain approval of, at the time of construction, an alternative 30-year emission trajectory to the 10- and 20-year limits described immediately above; and (2) specifying the emission rate for each year during the 30-year period consistent with meeting a 30-year average emission rate of 1,000 lb CO_2/MWh. Such an option would provide coal-fired sources that intend to use a reduction technology, such as CCS, significant flexibility in how that reduction technology is implemented. They could install the technology as part of the original project but use some or all of the initial ten year period to optimize the system. Such flexibility could be particularly useful to early adopters (i.e., ''first movers'') of the technology. Alternatively, they could delay installation of the technology for a period of up to ten years to take advantage of advancements in the technology that could reduce costs and enhance performance. Under CAA section 111(b)(1)(B), the EPA is required to conduct a review of the new source standards in eight years and we intend at that time to review the availability and cost of CCS. As proposed, this 30-year averaging compliance option is available only to new coal- and pet coke-fired EGUs. We do not believe that it is necessary for NGCC units, as they should be able to meet the proposed performance with no need for add-on technology. We also solicit comment on the need to extend the applicability for the 30-year averaging compliance option to other fossil fuels beyond just coal and pet coke.

b. *Rationale.* Today's proposal to combine the relevant parts of the Da and KKKK categories is authorized under CAA section 111(b)(1)(A) because that provision authorizes the EPA, after drawing up the list of affected source categories, to ''revise'' that list from time to time. Combining the relevant parts of the categories, as the EPA proposes to do, is one method to ''revise'' the list. Moreover, the EPA's action to combine the relevant parts of the categories is reasonable because with the combination, all new fossil fuel-fired electricity generating units that meet specified minimum criteria will be subject to the same requirements, and therefore will be treated alike because they serve the same function, that is to serve baseload or intermediate demand. The EPA is not including stationary simple cycle turbines in this rule because they generally operate differently than the other units covered by today's rule. The units covered by today's rule are generally used to serve baseload or intermediate demand, while simple cycle turbines are generally used much less often (and thus have lower GHG emissions) and are generally used to meet peak demand rather than base or intermediate load requirements.

Today's proposal does not apply to new sources in non-continental areas, which include Hawaii and the territories. This is because non-continental areas do not have available pipeline quality natural gas and, accordingly, a natural-gas-fired plant that could comply with the 1,000 lb CO_2/MWh may not be feasible. At present, we do not have information to identify what types of new power plants may be constructed in those areas. Those types of power plants may range from liquified natural gas (LNG)-, to oil-, to coal-fired to renewables. Our lack of more specific information precludes us from proposing, at this time, a standard for new sources in non-continental areas.

Today's proposal to require an emission rate of 1,000 lb CO_2/MWh meets the requirements for a ''standard of performance,'' as defined under CAA section 111(a)(1). This proposed standard is based on the degree of emission limitation achievable through natural gas combined cycle generation. NGCC qualifies as the ''best system of emission reduction'' (BSER) that the EPA has determined has been adequately demonstrated because NGCC emits the least amount of CO_2 and does so at the least cost. We propose that a NGCC facility is the best system of emission reduction for two main reasons. First, natural gas is far less polluting than coal. Combustion of natural gas emits only about 50 percent of the CO_2 emissions that the combustion of coal does per unit of energy generated. Second, new natural gas-fired EGUs are less costly than new coal-fired EGUs, and as a result, our Integrated Planning Model (IPM) model projects that for economic reasons, natural gas-fired EGUs will be the facilities of choice until at least 2020,

[21] Thus, today's rulemaking does not affect the Da and KKKK categories for conventional pollutants and does not affect the KKKK category for simple cycle turbines.

which is the analysis period for this rulemaking. Indeed, our IPM model does not project construction of any new coal-fired EGUs during that period. This state of affairs has come about primarily because technological developments and discoveries of abundant natural gas reserves have caused natural gas prices to decline precipitously in recent years and have secured those relatively low prices for the near-future. Importantly, because the IPM modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance in today's rulemaking — which is based on the emission rate of a new NGCC unit — does not add costs. In addition, compared to coal-fired EGUs, natural gas-fired EGUs have fewer nonair quality health and environmental impacts. This is true under not only a set of base-case assumptions, but also under a sensitivity considering significantly higher gas prices.

The just-described reasons are sufficient as a legal matter to justify today's proposed actions to combine source categories and establish the 1,000 lb CO_2/MWh standard. Such a standard could also be met today by new coal-fired units using CCS. In addition, we propose to include the compliance alternative of allowing new coal- and pet coke-fired power plants to meet the 1,000 lb CO_2/MWh standard over a 30-year period so that plant developers can take advantage of future advancements cost savings in CCS technology that could lower its cost. This compliance alternative allows owners/operators to install CCS when the unit is first constructed but also provides the operational flexibility that may be necessary to optimize the performance and to have additional time to address any startup challenges related to issues such as business arrangements related to the sale or storage of the captured CO_2.

We recognize that, in light of a number of economic factors, including the increased availability and significantly lower price of natural gas, energy industry modeling forecasts uniformly predict that few, if any, new coal-fired power plants will be built in the foreseeable future. For these economic reasons, and independent of this proposed standard, the fossil fuel-fired electricity generating industry has been trending towards increased use of natural gas and decreased use of coal for new generating capacity. Today's proposed action is consistent with that trend; but, at the same time, today's proposal is not intended to affect that apparent trend.

We recognize that some owners/operators may nevertheless seek to construct new coal-fired capacity. This may be beneficial from the standpoint of promoting energy diversity, and today's proposal does not interfere with construction of new coal-fired capacity. In the first instance, a new coal-fired power plant may be able to meet the 1,000 lb CO_2/MWh standard by installing CCS at the time of construction. At present, while CCS would add considerably to the costs of a new coal-fired power plant, there are sources of funding available to support the deployment of CCS, including a limited number of government demonstration programs.[22] Even if companies decide to construct a few new coal-fired power plants under any circumstance, those few may well have access to those government programs.

The proposed 30-year averaging compliance option adds additional flexibility for new coal- and pet coke-fired power plants by allowing them to construct and begin operations without CCS, and then to install and operate CCS at some time in the future, as long as they install CCS within ten years and operate it in a manner that allows them to meet the 1,000 lb CO_2/MWh standard, on a weighted average basis, over the 30-year period.

We expect that the costs of CCS will decline in the future as CCS matures and is utilized more widely. Today's action, if finalized, would promote utilization and further development of CCS by making it clear that CCS would be necessary for new coal-fired power plants to meet the performance standard. The prospect of declining CCS costs, in conjunction with the possibility of continued availability of additional funding mechanisms (e.g. demonstration funding such as Department of Energy (DOE) grants, tax credits (for investment and/or EOR), State incentives such as clean energy standards), and sale of other usable products such as CO_2, sulfur and hydrogen based products, indicates that CCS may well be sufficiently accessible in the near term to the few coal-fired power plants that are expected to commence construction. Thus, the 30-year averaging compliance option, along with the potential opportunities for funding to implement CCS immediately, helps to alleviate any concerns that today's action could restrict new coal-fired construction.

It should be noted that we are not required to justify the 30-year averaging compliance option on grounds that it qualifies as the ''best system of emission reduction'' adequately demonstrated, and we are not stating in this action whether that compliance alternative does or does not qualify as such. Thus, it is not necessary to determine that our expectation that costs will go down meets the standards for determining that CCS is ''adequately demonstrated.'' Rather, to reiterate, the 30-year averaging compliance option, along with the opportunity to implement CCS to meet the 1,000 lb CO_2/MWh standard immediately upon startup, make CCS an available option for the limited number of new coal-fired power plants that may construct to serve the policy goals of promoting energy diversity, as well as other policy objectives.[23] Indeed, by clarifying that, in the future, new coal-fired power plants will need to implement CCS, this rulemaking eliminates uncertainty about the status of new coal and may well enhance the prospects for new coal-fired generation.

In addition, there may also be other potential compliance options available that were not considered in this proposal. In the analysis for today's proposal, the EPA did not include unique treatment of CO_2 emissions from biologically-based material, otherwise called biogenic CO_2 emissions.[24]

In 2011, the EPA prepared and submitted the draft Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources (*http://www.epa.gov/climatechange/emissions/biogenic_emissions/study.html*). The draft Framework includes both a detailed examination of the scientific and technical issues related to accounting for biogenic CO_2 emissions from stationary sources, and a proposed method to account for a stationary source's onsite CO_2 emissions, taking the biological cycling of carbon into consideration, in a scientifically and technically rigorous manner. The independent Science Advisory Board (SAB) has convened a Biogenic Carbon

[22] A number of the sources that EPA has identified as transitional sources have received some form of DOE financial assistance to demonstrate CCS. In addition, several additional projects have received funding but have not yet received air permits. Beyond these projects, prospects for additional federal funding are dependent on the overall budget process.

[23] EIA analysis (AEO 2012 early release) shows that ''coal remains the dominant energy source for electricity generation.''

[24] Biologically-based material is defined as non-fossilized and biodegradable organic material originating from modern or contemporaneously grown plants, animals or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

Emissions Panel (*http://yosemite.epa.gov/sab/sabproduct.nsf/0/2F9B572C712AC52E8525783100704886?OpenDocument*) to conduct a peer review of the draft Framework. The peer review report will be finalized later in 2012.

The SAB's peer review of the EPA's discussion on the science related to the impacts of biogenic CO_2 is not yet finalized and the EPA looks forward to the SAB's conclusions later in 2012. Given that the SAB's peer review is ongoing, the EPA is not suggesting specific methods of accounting or otherwise making particular proposals for treatment of biogenic CO_2 emissions in any stationary source program, including NSPS. As more information, including the SAB peer review, becomes available, the EPA will consider its options and move forward as warranted.

c. *Requirements and Rationale for NSPS Modifications for GHGs.* For purposes of today's action, the EPA does not have a sufficient base of information to develop a proposal for the affected sources that may be expected to take actions that would constitute ''modifications'' (as defined under the EPA's NSPS regulations) for GHGs and therefore be subject to requirements for new sources. As a result, the EPA is not proposing requirements for NSPS modifications for GHGs.[25]

The EPA's current regulations define an NSPS ''modification'' as a physical or operational change that increases the source's maximum achievable hourly rate of emissions, but specifically exempt from that definition pollution control projects, which are projects that entail the installation of pollution control equipment or systems. Based on current information, most of the projects that we believe EGUs are most likely to undertake in the foreseeable future that could increase the maximum achievable hourly rate of CO_2 emissions would constitute pollution control projects. In many cases, those projects would involve the installation of add-on control equipment required to meet CAA requirements for criteria and air toxics air pollutants. These increases in CO_2 emissions would generally be small and would occur as a chemical byproduct of the operation of the control equipment. In other cases, those projects would involve equipment changes to improve efficiency to meet the requirements of a future 111(d) rulemaking for existing sources and would have the effect of increasing a source's maximum achievable hourly emission rate (lb CO_2/hr), even while decreasing its actual output based emission rate (lb CO_2/MWh). Because all of these actions would be treated as pollution control projects under the EPA's current NSPS regulations, they would be specifically exempted from the definition of modification.

Our base of knowledge concerning NSPS modifications has depended largely on the enforcement actions brought against power plants and on self-reporting by power plants. Over the lengthy history of the NSPS program, those have been too few in number to allow us to develop a sufficiently robust base of knowledge to propose a standard of performance for NSPS modifications for GHGs at this time.

In addition, the sources that took these actions vary widely one from another, and the types of actions were disparate. In light of this, as noted, we do not have adequate information as to the types of actions that qualify as modifications, the amount of increase in CO_2 emissions they cause, the types of control measures, or the costs and effectiveness of control measures, on which to base a proposed standard of performance. Therefore, in today's action, we are not proposing a standard of performance for modifications. We note that the statute contemplates that in circumstances such as these (where section 111(d) is implicated), sources not subject to the new source standards would be treated as existing sources subject to section 111(d).

In today's action, we solicit comment on the types of modifications power plants may undertake and the appropriate control measures. Depending on the information we develop, we may issue proposed standards of performance in the future.

d. *Requirements for Transitional sources.* The EPA is aware that approximately 15 proposed EGUs have received CAA permitting authority approval for their preconstruction permits, but may not have ''commenced construction'' by the date of today's proposed rulemaking.

A few of these sources have taken additional action preparatory to commencing construction. For this proposed rule, these sources that, as of the date of this proposal, have a PSD permit and are poised to commence construction within the very near future are referred to as ''transitional sources.'' We are aware that approximately six of these sources have plans to implement CCS to some degree.

CAA section 111 provides by its terms that sources that have not ''commenced construction'' before the date of proposed standards for new sources will be subject to the NSPS when they do commence construction. The EPA's regulations define ''commenced construction'' as, in general, undertaking a continuous program of construction or entering into a binding contract to do so. 40 CFR 60.2.

Commenters[26] have pointed out that absent different treatment, transitional sources will be subject to the same requirements that apply to new sources that did not obtain their permit before the date of proposal. These commenters have suggested that today's proposed rule should treat transitional sources differently, especially in light of the substantial redesign that meeting such the proposed standard would have and the impact that redesign would have on the schedule for a project that was nearly ready to commence construction. The transitional sources at issue are coal-fired EGUs that, absent special treatment, would be subject to the standard of performance proposed in this rulemaking.

In today's proposed rulemaking, the EPA is not proposing a standard of performance for transitional sources, which we define as sources that have been issued a PSD permit by the date of proposal (including sources that have approved permits that are in the process of being amended, if those sources are intending to install CCS as evidenced by participating in any of the DOE CCS funding programs, either loan guarantee or grant programs) and that commence construction within 12 months of the date of publication of this proposal in the **Federal Register**. Upon finalization of this rulemaking without a standard of performance applicable to these sources, they will not be treated as new sources subject to the specific limitations set forth in the final new source standards. These sources would remain obligated, by the terms of their permits, to construct and operate in accordance with their permits. In addition, these sources will be treated as existing sources and would be subject to any requirements that a State promulgates to meet its obligations under section 111(d). Sources that do not commence construction within 12 months of the date of this proposed action will be subject to this standard of performance for new sources.

[25] Note that any analysis of the cost and feasibility of CCS that EPA has undertaken for purposes of this proposal has focused solely on new sources. In today's action, EPA has not undertaken any analysis of the cost or feasibility of CCS for existing units that undergo modifications.

[26] As mentioned elsewhere, the EPA held a series of listening sessions and allowed for a period of additional comment after announcing it was moving forward with development of new source performance standards for GHGs emitted from fossil fuel-fired EGUs. The term ''commenters'' here refers to those who commented during the listening sessions or during the subsequent comment period.

e. *Requirements for Reconstructed Sources, and Rationale.* The EPA's CAA section 111 regulations provide that reconstructed sources are to be treated as new sources and, therefore, subject to new source standards of performance. The regulations define reconstructed sources as, in general, existing sources (i) that replace components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility, and (ii) for which compliance with standards of performance for new sources is technologically and economically feasible. 40 CFR 60.15.

As with NSPS modifications, our base of knowledge concerning reconstructions has depended largely on the enforcement actions brought against power plants and on self-reporting by power plants. Over the lengthy history of the NSPS program, those have been too few in number to allow us to develop a sufficiently robust base of knowledge to propose a standard of performance for reconstructions for GHGs at this time. Thus, we lack adequate information about the type of source; the type of changes; the extent of emissions increases; and the type of control measures, including their cost and emissions reductions, that we need to propose a standard of performance for reconstructions.

As a result, in today's action, the EPA is not including a proposal for reconstructed units for GHGs. Instead, we solicit comment on how we should approach reconstructions and, depending on the information we receive, we may propose and finalize a standard for reconstructions at a later time.

6. Summary of Emissions Impacts, Costs and Benefits

Our IPM modeling, using Energy Information Administration (EIA) reference case assumptions, projects that there will be no construction of new coal-fired generation without CCS. In addition we examined a case with higher future electric demand and another case with higher future natural gas prices. We did not see any additional new construction of coal-fired generation through 2030 in either of these cases. Under the relevant assumptions, we do not project that this rule will impose notable costs.

We also examined a scenario with both increased future natural gas prices and increased future electric demand. In this sensitivity case we saw small amounts of coal-fired generation being built in 2030. Even under this sensitivity analysis with small amounts of new coal generation under conditions of high natural gas prices and simultaneously high electricity demand in 2030, we do not project that this proposed rule will impose notable costs upon sources. (See the RIA for further discussion of sensitivities).

While this proposed rule also will not have direct impact on U.S. emissions of greenhouse gases under expected economic conditions, it provides assurance that emission rates from new fossil fuel-fired generation will not exceed the level of the standard and will send a strong signal both domestically and internationally. Domestically, this proposed rule can further stimulate investment in CCS and other clean coal technologies, by making it clear that such technologies do provide a clear path forward for new coal-fired generating capacity. Internationally, this rule may encourage others to consider less GHG-intensive forms of power generation.

B. Does this action apply to me?

The entities potentially affected by the proposed standards are shown in Table 1 below.

TABLE 1—POTENTIALLY AFFECTED ENTITIES [a]

Category	NAICS Code	Examples of potentially regulated entities
Industry	221112	Fossil fuel electric power generating units.
Federal Government	[b] 221112	Fossil fuel electric power generating units owned by the federal government.
State/Local Government	[b] 221112	Fossil fuel electric power generating units owned by municipalities.
Tribal Government	921150	Fossil fuel electric power generating units in Indian Country.

[a] Include NAICS categories for source categories that own and operate electric power generating units (including boilers and stationary combined cycle combustion turbines).
[b] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive but rather to provide a guide for readers regarding entities likely to be affected by this proposed action. To determine whether your facility, company, business, organization, etc., would be regulated by this proposed action, you should examine the applicability criteria in 40 CFR 60.1. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

II. Background

A. Statutory Background for This Rule

Clean Air Act section 111 establishes mechanisms for controlling emissions of air pollutants from stationary sources. As a preliminary step, CAA section 111(b)(1)(A) requires the EPA to list categories of stationary sources that the Administrator, in his or her judgment, finds ''cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' [27]

Once it has listed a source category, the EPA establishes ''standards of performance'' that apply to new sources, which are sources that are constructed, or that undertake modifications or reconstruction, after the EPA proposes the standards of performance for the relevant source category. CAA section 111(b)(1)(B). Specific statutory and regulatory provisions define what constitutes a modification or reconstruction of a facility. An existing facility undertakes a modification if it undergoes ''any physical change * * * or change in the method of operation * * * which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' CAA section 111(a)(4). The EPA's NSPS regulations provide exemptions for several types of changes, including the installation of pollution control projects. 40 CFR 60.2, 60.14(e). An existing facility undertakes a reconstruction if it replaces components to such an extent that the capital costs of the new equipment or components exceed 50 percent of what is believed to be the cost of a completely new facility. 40 CFR 60.15. In promulgating standards of performance, the EPA has significant

[27] The EPA has made endangerment findings under this section for more than 60 stationary source categories and subcategories that are now subject to NSPS.

discretion to create subcategories based on source type, class or size. CAA section 111(b)(2).

Clean Air Act section 111(a)(1) defines a ''standard of performance'' as—

> a standard for emissions of air pollutants which reflects 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.

We call this level of control the best system of emission reduction (BSER).[28] The standard that the EPA develops, based on the BSER, is commonly a numerical emissions limit, expressed as a performance level (e.g., a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions.

B. Overview of Climate Change Impacts From GHG Emissions

In 2009, the EPA Administrator issued the 2009 Endangerment Finding,[29] under CAA section 202(a)(1), as part of the process for promulgating the Light Duty Vehicle Rule.[30] With the Endangerment Finding, the Administrator found that elevated concentrations of GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare. These adverse effects on public health and welfare are summarized here, and described in more detail in the RIA. As explained in the Endangerment Finding, the EPA made this determination based primarily upon the recent, major assessments by the U.S. Global Change Research Program (USGCRP), Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC).[31] In brief, these assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change problem, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review and acceptance. Below is a brief, non-comprehensive summary of effects noted in the Endangerment Finding and the assessment reports.

1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change threatens public health through a number of impacts such as increases in hot weather, ozone pollution, and the severity and frequency of extreme weather events. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

By increasing higher average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also leads to decreases in cold-related mortality, some evidence suggests that the net impact on mortality is more likely to be adverse. Heat is already the leading cause of weather-related deaths in the U.S.

Climate change is expected to increase ozone pollution over broad areas of the country including large population areas with unhealthy surface ozone levels. Ozone health studies indicate that elevated surface ozone increases risks of premature death, acute bronchitis, heart attacks, asthma aggravation, and other respiratory effects.

Public health threats also stem from increases in intensity or frequency of extreme weather associated with climate change, such as increased hurricane intensity, increased frequency of intense storms and heavy precipitation. The assessment literature indicates that there is the potential for hurricanes to become more intense, and there is some evidence that Atlantic hurricanes have already become more intense. Hurricanes and floods from human-induced climate change can cause deaths, injuries, waterborne diseases, and mental health problems such as post-traumatic stress disorders. Drownings and other health impacts from coastal storms and storm surges are expected to increase due to rising sea levels.

2. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Climate change is expected to have numerous effects on public welfare. Large areas of the country are at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas face increased risks from storm and flooding damage to property, as well as adverse impacts from sea level rise such as land loss due to inundation, erosion, wetland submergence, and habitat loss.

Climate change is expected to result in an increase in peak electricity demand, and changes in extreme weather threaten energy, transportation, and water resource infrastructure. Climate changes may exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities. Over the 21st century, climate change will fundamentally rearrange U.S. ecosystems.

It is possible that in the next few decades, adverse effects in certain parts of the agriculture and forestry sectors—such as enhanced pest and weed growth, increased surface ozone, changes in the intensity and frequency of droughts and heavy storms, and increased wildfires—may be offset by benefits resulting from a stimulatory carbon dioxide effect and a longer growing season. However, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture, and forest productivity as temperatures continue to rise, with the potential for significant disruptions and crop failure.

Human-induced climate change has the potential to be far-reaching and multidimensional. Given the long atmospheric lifetime of the six GHGs,[32] which range from roughly a decade to centuries, future atmospheric greenhouse gas concentrations for the remainder of this century and beyond will be influenced not only by future emissions but indeed by present-day emissions. The severity of all the described risks and impacts is likely to increase over time with accumulating GHG concentrations and the associated temperature increases and precipitation changes. Finally, these impacts are global, and may exacerbate problems that raise humanitarian, trade, and national security issues for the U.S.

3. Climate Impacts Detailed in Recent NRC Assessments

Since the EPA issued the 2009 Endangerment Finding, the NAS, which is a society established by an Act of Congress that is composed of distinguished scholars engaged in scientific and engineering research, has

[28] This level of control has historically been referred to as best demonstrated technology (BDT).

[29] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act.'' 74 FR 66496 (December 15, 2009).

[30] ''Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule.'' 75 FR 25324 (May 7, 2010).

[31] 74 FR 66510–66511.

[32] Carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), perflurocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF_6).

issued assessments with similar conclusions to those of the assessments upon which the EPA based the Endangerment Finding. In May 2010, the NRC, which is the operating arm of the National Academy of Sciences (NAS) that conducts most of the science policy and technical work, published its comprehensive assessment, ''Advancing the Science of Climate Change'' (the 2010 NRC Assessment).[33] It concluded that ''climate change is occurring, is caused largely by human activities, and poses significant risks for—and in many cases is already affecting—a broad range of human and natural systems.'' [34] Furthermore, the NRC stated that this conclusion is based on findings that are ''consistent with the conclusions of recent assessments by the U.S. Global Change Research Program, the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report, and other assessments of the state of scientific knowledge on climate change.'' [35] These are the same assessments that served as the primary scientific references underlying the 2009 Endangerment Finding. The 2010 NRC Assessment also warned of risks associated with abrupt changes and surprises that might occur when certain thresholds are crossed, such as the release of large quantities of GHGs stored in frozen soils in the Arctic or irreversible drying and desertification in the subtropics; and of potential for broad, ''catastrophic'' impacts on marine ecosystems resulting from ocean acidification.

Another NRC assessment, ''Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millenia'', was published in 2011 (the 2011 NRC Assessment). This report found that climate change due to CO_2 emissions will persist for many centuries. The report also estimates a number of specific climate change impacts, finding that every degree Celsius (°C) of warming could lead to increases in heavy rainfall and decreases in crop yields and Arctic sea ice extent, along with other precipitation and stream flow changes. The assessment also found that with an increase of 4 °C, the average summer would be as warm as the warmest summers of the past century, that for an increase of 1 to 2 °C the area burnt by wildfires in western North America will likely more than double, that coral bleaching and erosion will increase due both to warming and ocean acidification, and that sea level will rise 1.6 to 3.3 feet by 2100 in a 3 °C scenario. The assessment notes that many important aspects of climate change are difficult to quantify but that the risk of adverse impacts is likely to increase with increasing temperature, and that the risk of surprises can be expected to increase with the duration and magnitude of the warming. Importantly, these recent NRC assessments represent another independent and critical inquiry of the state of climate change science, separate and apart from the previous IPCC, NRC, and USGCRP assessments.

C. GHGs From Fossil Fuel-Fired Power Plants

Fossil fuel-fired electric utility generating units are by far the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the U.S. This section describes the amount of those emissions and places that amount in the context of the national inventory of GHGs.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks [36] (the U.S. GHG Inventory) to comply with existing commitments under the United Nations Framework Convention on Climate Change. This inventory, which includes recent trends, is presented by industrial sectors. It is the source for the information provided in Table 2 below concerning total U.S. anthropogenic emissions and sinks of GHGs and CO_2 emissions, by industrial sector—including fossil fuel-fired EGUs—for the years 1990, 2000, and 2009.

TABLE 2—U.S. GHG EMISSIONS AND SINKS BY SECTOR

[Teragram Carbon Dioxide Equivalent (Tg CO_2 Eq.)] [37]

Sector	1990	2000	2009
Energy	5,287.8	6,168.0	5,751.1
Industrial Processes	315.8	348.8	282.9
Solvent and Other Product Use	4.4	4.9	4.4
Agriculture	383.6	410.6	419.3
Land Use, Land-Use Change and Forestry (Emissions)	15.0	36.3	25.0
Waste	175.2	143.9	150.5
Total Emissions	6,181.8	7,112.7	6,633.2
Land Use, Land-Use Change and Forestry (Sinks)	(861.5)	(576.6)	(1,015.1)
Net Emissions (Sources and Sinks)	5,320.3	6,536.1	5,618.2

Energy-related CO_2 emissions are the largest contributor to total U.S. GHG emissions, representing 86.7 percent of total 2009 GHG emissions. In 2009, the electric power sector—consisting of those entities whose primary business is the generation of electricity—accounted for 40 percent of all energy-related CO_2 emissions. The transportation sector, with emissions principally from the combustion of gasoline, diesel, and jet fuel, was the second-largest source, at 32 percent of the total. Other energy-related CO_2 emission sources included industrial, residential, and commercial fossil fuel combustion, natural gas and petroleum systems, and incineration of waste.

Direct fuel use in the residential and commercial sectors accounted for 26 percent of total CO_2 emissions in 2009. Total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2000 and 2009, are shown below in Table 3.

[33] NRC (2010). Advancing the Science of Climate Change. National Academy Press. Washington, DC.

[34] NRC (2010). Advancing the Science of Climate Change. National Academy Press. Washington, DC. Page 3.

[35] NRC (2010). Advancing the Science of Climate Change. National Academy Press. Washington, DC. Page 286.

[36] ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009'', Report EPA 430–R–11–005, United States Environmental Protection Agency, April 15, 2011.

[37] From Table 2–3 of the EPA GHG Emissions and Sinks Inventory, EPA 430–R–11–005.

TABLE 3—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS

[Tg CO_2 Eq.]

GHG Emissions	1990	2000	2009
Total CO_2 from fossil fuel combustion	1,820.8	2,296.9	2,154.0
—from coal	1,547.6	1,927.4	1,747.6
—from natural gas	175.3	280.8	373.1
—from petroleum	97.5	88.4	32.9
From use of limestone and dolomite	2.6	2.5	3.8
Total CH_4—stationary combustion	0.6	0.7	0.7
Total N_2O—stationary combustion	8.1	10.0	9.0

We are aware that nitrous oxide (N_2O) (and to a lesser extent, methane (CH_4)) may be emitted from fossil fuel-fired EGUs, especially from coal-fired circulating fluidized bed (CFB) combustors and from units with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems installed for NO_X control. We are not proposing separate N_2O or CH_4 emission limits or an equivalent CO_2 emission limit in today's action because of a lack of available data for these affected sources. Additional information on the quantity and significance of emissions and on the availability of cost-effective controls would be needed before proposing standards for these pollutants. The estimated emissions for N_2O and CH_4 from fossil fuel-fired EGUs (9.0 and 0.7 Tg of CO_2 equivalent, respectively) is about 0.4 percent of total CO_2 equivalent emissions from fossil fuel-fired electric power generating units. We are requesting comment on this approach and on the need to collect additional data on N_2O and CH_4 emissions from these affected sources.

D. Litigation Directly Leading to This Rule

As discussed below, in section II.E., on February 27, 2006, the EPA published a final rule that revised the standards of performance for criteria pollutant emissions of EGUs included in the Da category. ''Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units,'' 71 FR 9866 (Feb. 27, 2006) (the ''2006 Final Rule''). The 2006 Final Rule did not establish standards of performance for GHG emissions. Two groups of petitioners filed petitions for judicial review of this rule in the U.S. Court of Appeals for the District of Columbia Circuit (the Court), contending, among other things, that the rule was required to include standards of performance for GHG emissions from EGUs. The two groups of petitioners were (1) the States of New York, California, Connecticut, Delaware, Maine, New Mexico, Oregon, Rhode Island, Vermont, and Washington, the Commonwealth of Massachusetts, the District of Columbia, and the City of New York (collectively ''State Petitioners''); and (2) Natural Resources Defense Council (NRDC), Sierra Club, and Environmental Defense Fund (EDF)(collectively ''Environmental Petitioners'').

The portions of State and Environmental Petitioners' petitions for review of the 2006 Final Rule that related to GHG emissions were severed from other petitions for review of that rule, and were formally pending before the Court under the caption *State of New York, et al.* v. *EPA,* No. 06–1322. Following the U.S. Supreme Court's decision in *Massachusetts,* discussed above, the Court, upon motion from the EPA, remanded the 2006 Final Rule for further consideration of the issues related to GHG emissions in light of *Massachusetts.* The EPA did not act on that remand. To avoid further litigation, the State and Environmental Petitioners and the EPA negotiated a proposed settlement agreement that set deadlines for the EPA to propose and take final action on (1) a rule under CAA section 111(b) that includes standards of performance for GHGs for new and modified EGUs that are subject to 40 CFR part 60, subpart Da; and (2) a rule under CAA section 111(d) that includes emission guidelines for GHGs from existing EGUs that would have been subject to 40 CFR part 60, subpart Da if they were new sources. Pursuant to CAA section 113(g), the EPA published a notice of the proposed settlement agreement in the **Federal Register,** and provided for a public comment period. 75 FR 82392 (December 30, 2010).[38] The EPA considered the comments received and concluded that they did not disclose facts or considerations indicating that the proposed settlement agreement was inappropriate, improper, inadequate or inconsistent with the CAA. Therefore, the EPA concluded that the proposed settlement agreement should be finalized.

E. Coordination With Other Rulemakings

EGUs are the subject of several CAA rulemakings that have been recently completed. The EPA recognizes that it is important that all of these efforts achieve their intended environmental objectives in a common sense manner. The confluence of these rulemakings allows the industry to look across the regulatory requirements and design cost effective integrated compliance strategies.[39]

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR)[40]. 76 FR 48208 (August 8, 2011). Also known as the Transport Rule, the CSAPR requires a total of 28 states and the District of Columbia to improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other States. The CSAPR applies to 3,642 EGUs at 1,081 coal-, gas- and oil-fired facilities in the eastern half of the U.S. By 2014, combined with other final state and EPA actions, the CSAPR will reduce power plant SO_2 emissions by 73 percent and NO_X emissions by 54 percent from 2005 levels in the CSAPR region. The CSAPR was scheduled to begin on January 1, 2012. However, on December 30, 2011, the U.S. Court of Appeals for the DC Circuit issued a ruling to stay the rule pending judicial review. This decision is not a ruling on the merits of the CSAPR. While this decision delays implementation of the

[38] Copies of the **Federal Register** notice, the settlement agreement, other supporting documents and the comments received are available online at fdms.gov under docket EPA–HQ–2010–1057.

[39] We include this discussion of other rulemakings for background purposes. The effort to coordinate rulemakings does not provide a defense to a violation to the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

[40] On December 15, 2011, EPA finalized a supplemental rule (76 FR 80760, December 27, 2012) to include five additional states in the CSAPR ozone season NO_X program. On February 7, 2012, EPA issued two sets of minor adjustments to the CSAPR (77 FR 10324, February 21, 2012).

CSAPR and the significant health benefits associated with the rule, it leaves the Clean Air Interstate Rule (CAIR), the predecessor regulation to CSAPR, in place while the Court considers the merits of the challenges to the CSAPR. Oral arguments are scheduled for April 13, 2012.

On December 16, 2011, the EPA signed the Mercury and Air Toxic Standards (MATS) rule to reduce emissions of mercury and other HAP emissions from coal- and oil-fired power plants. This regulation requires investments in pollution controls to reduce emissions of mercury, other metals and acid gases by 2015 or 2016. In the same notice, the EPA also revised the NSPS for criteria pollutants from these sources. Because the control technologies and strategies that reduce SO_2 can also reduce or help to reduce HAP emissions, coordinating compliance strategies for the CSAPR and MATS rules, including the revised NSPS for criteria pollutants, will allow cost-effective compliance options.

In April, 2011, the EPA proposed standards under the Clean Water Act (CWA) to reduce injury and death of fish and other aquatic life caused by cooling water intake structures existing at power plants and factories. 76 FR 22174 (April 20, 2011). These facilities pull in large volumes of cooling water from lakes, rivers, estuaries or oceans to cool their machinery. The EPA is currently considering a wide range of comments to this proposal.

The EPA recognizes that it is important that each of these efforts achieves its intended environmental objectives in a common-sense, cost effective manner, that is consistent with the underlying statutory requirements and that allows the industry to comply with all of its obligations under these rules as efficiently as possible and to do so by making coordinated investment decisions and, to the greatest extent possible, by adopting integrated compliance strategies. In addition, EO 13563 states that ''[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote * * * coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.'' Recent guidance from the Office of Information and Regulatory Affairs has emphasized the importance of, where appropriate and feasible, considering cumulative effects and of seeking to harmonize rules in terms of both content and timing.

Thus, the EPA recognizes that it needs to approach these rulemakings, to the extent that its legal obligations permit, in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that the rulemakings must achieve.

F. PSD and Title V Implications

Commenters have asked whether the rulemaking the EPA is proposing today has implications for EGUs and other stationary sources under the prevention of significant deterioration (PSD) and Title V programs. We discuss this issue in section VI, below, and we include relevant background information in that discussion.

G. Stakeholder Input

The EPA has been engaged in extensive interactions with many different stakeholders on the subjects of climate change, source contributions, and potential emission reduction opportunities. These stakeholders have included industries, environmental organizations, and many regional, State, and local air quality management agencies that have been actively engaged in efforts to address GHG emissions over a period of several years. In addition to these conversations, as part of developing this proposed rule, the EPA held five listening sessions in February and March 2011 to obtain additional information and input from key stakeholders and the public. Each of the five sessions had a particular target audience: The electric power industry, environmental and environmental justice organizations, States and Tribes, coalition groups, and the petroleum refinery industry. Each session lasted two hours and featured a facilitated round table discussion among stakeholder representatives who were identified and selected for their expertise in the CAA standard-setting process. The EPA had asked key stakeholder groups to identify these round table participants in advance of the listening sessions. The EPA accepted comments from the public at the end of each session and via the electronic docket system.

From the listening sessions and written submissions, the EPA received a wide range of comments and ideas for this proposed rule. The main topics of the comments, which concerned requirements for both new and existing sources, included the following:

- Feasibility and availability of control technologies
- Output-based standards
- Subcategorization factors
- Fleet-wide averaging
- Neutrality of fuels
- Role of efficiency improvements
- Equivalency of state and regional reduction programs
- Recognition of early action by industries and states achieving reductions
- Use of a multi-pollutant, multi-media approach
- Market-based flexibility
- Use of a tiered structure, with requirements evolving over time
- Credit for replacement of older, less efficient generation units
- Role of biomass
- Consideration of compliance issues arising from conflicts with other regulatory programs
- Schedule for proposing and promulgating this rule
- Small business impacts

Comments submitted via the electronic docket system concerning development of this proposed rule are available at *www.regulations.gov* (docket number EPA–HQ–OAR–2011–0090).

III. Proposed Requirements for New Sources

This section describes the proposed requirements in this rulemaking for new sources. Our rationale for these proposed requirements is provided in Section IV of this preamble.

A. What is the affected source?

Sources affected by today's proposal for new source provisions are sources that are considered both covered EGUs as defined by this rule and ''new'' sources as defined under the provisions of CAA section 111.

1. Covered EGUs, Generally

The EPA is proposing to define a covered EGU, which is a source that is subject to this rule, as any fossil fuel-fired combustion unit that supplies more than one-third of its potential annual electric output and more than 25 MW net-electrical output (MWe) to any utility power distribution system for sale, with certain exceptions noted below. For this proposed rule, covered EGUs include electric utility steam generating units (''boilers''), stationary combined cycle combustion turbines and their associated HRSG) and duct burners; and IGCC units, including their combustion turbines and associated HRSG. However, for purposes of this rule, covered EGUs do not include stationary simple cycle combustion turbines or EGUs located in Hawaii or other non-continental areas. In addition, units subject to emission requirements

under CAA section 129 would not be subject to requirements under this proposed rule.

2. CO_2 Emissions Only

This action proposes to regulate covered EGU emissions of CO_2, and not other constituent gases of the air pollutant GHG, although we identify the pollutant we propose to regulate as GHGs. Note that emissions of criteria pollutants for covered EGUs remain covered under 40 CFR part 60 subparts Da and KKKK.

3. ''New'' Sources

CAA section 111(a)(2) defines a ''new source'' as ''any stationary source, the construction or modification of which is commenced after publication of regulations (or, if early, proposed regulations) prescribing a standard of performance under [CAA section 111] which will be applicable to such source.'' In contrast, CAA section 111(a)(6) defines an ''existing source'' as ''any stationary source other than a new source.'' The definition of a ''new source'' applies according to its terms for purposes of this rulemaking, except that special considerations come into play for sources undertaking physical or operational changes, transitional sources, and sources undertaking reconstruction, as discussed below in Section V of this preamble.

B. What emissions limitations must I meet?

In this rulemaking, the EPA is proposing a standard of performance (NSPS), and we are requesting comment on a 30-year averaging compliance option, for CO_2 emissions from affected sources, which are new fossil fired EGUs described above in Section III.A.

1. Standard of Performance

The standard of performance is a gross output-based CO_2 emission limit expressed in units of emissions mass per unit of useful recovered energy (specifically, in pounds per megawatt-hour (lb/MWh)). This emission limit would be effective upon the effective date of the final action.

We are not proposing any subcategories for new affected sources. Instead, we are proposing a single output-based CO_2 emission limit that must be met by all affected sources.[41] Specifically, the EPA is proposing a standard of 1,000 lb CO_2/MWh, but, as discussed below, is taking comment on a range from 950 lb CO_2/MWh to 1,100 lb CO_2/MWh.

As discussed below, the proposed method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electrical energy output and useful thermal energy output, where applicable for combined heat and power (CHP) EGUs, over a rolling 12-month period. In the alternative, we solicit comment on requiring calculation of compliance on an annual (calendar year) period.

Under this proposal, no averaging or emissions trading among affected sources would be allowed.

We seek comment on all aspects of the proposed standard of performance, including using net, instead of gross, generation-based emissions rate measurement.

2. 30-Year Averaging Compliance Option

We also propose a 30-year averaging compliance option that would be available only for affected coal- and pet coke-fired sources that comply with the standard through the use of CCS. This approach involves a performance standard that includes both a 12-month annual average limit and a longer-term limit that may be met on an average basis by the end of a 30-year period. The 12-month limit is important because it is a practicably enforceable mechanism to ensure that the source is on a path to comply with the 30-year average limit. The annual limit will ensure that the source takes timely action to meet a 30-year limit. For instance, if meeting the 30-year limit was predicated on installing CCS technology before year eleven of operation, the annual compliance limits would provide an enforceable measure to ensure that CCS was installed and operating well before a 30-year average could be calculated. Note that after the 30th year, the source would be required to meet the 12-month annual average 1,000 lb CO_2/MWh emission limit.

Specifically, for the first ten years of operation, the affected source would be required to comply with a 12-month annual average CO_2 emissions limit based on the best demonstrated performance of a coal-fired facility without CCS, which is 1,800 lb CO_2/MWh (816 kg CO_2/MWh) (gross). This proposed emission limit can be met by modern coal-fired facilities using supercritical steam conditions, IGCC facilities, and pressurized CFBs boilers. By no later than the 11th year from the effective date of the rule, the facility would be required to meet a reduced emission limit of no more than 600 lb CO_2/MWh (272 kg CO_2/MWh) (gross) on a 12-month annual average basis for the remaining 20 years of the 30-year averaging period, such that the weighted average CO_2 emissions rate from the facility over the 30-year time period would be equivalent to the proposed standard of performance of 1,000 lb CO_2/MWh. This reduced emissions standard during the remainder of the 30-year period would be met with some level of CCS.[42]

For added flexibility, under this option, we are taking comment on allowing the owner/operator to select a different emission trajectory to achieving the 30-year average as long as the owner/operator obtains EPA approval of that rate before beginning operations. Such a trajectory would have to assure that, assuming similar amounts of operation in each year, the overall overage emission rate would be at or below the required 30-year average of 1,000 lb CO_2/MWh. For instance, if an owner or operator wished to operate at a rate of 2,000 lb CO_2/MWh for the first period, it would have to commit to something more stringent than achieving a 600 lb CO_2/MWh standard by the 11th year. Potential compliance pathways could include committing to a limit of 500 lb CO_2/MWh by the 11th year or committing to a limit of 600 lb CO_2/MWh by the 8th year.

The EPA is also soliciting comment on what additional requirements would be necessary to implement the 30-year averaging requirement. Specifically, if the owners or operators did not intend to install CCS when the unit commenced operation, they could be required to submit a plan that includes a location to store CO_2 and a schedule for construction and operation of their carbon capture system. The schedule would include key milestone dates such as soliciting proposals, obtaining financing, beginning construction, and beginning operation. The EPA requests comment on the appropriateness of including these, and/or other requirements to ensure that the owners or operators of the facility have adequate plans in place to meet the 30-year average emission rate requirement. Further, the shorter term emission limits for the entire 30-year period must be included in the source's title V permit. We solicit comment on the

[41] As discussed below, we are not proposing such a limit for modifications, transitional sources, or reconstructed sources.

[42] As discussed elsewhere, EPA is soliciting comment on whether the emissions standard that reflects CCS should be somewhat higher or lower than 1,000 lb CO_2/MWh, and whether the emissions standard that reflects supercritical efficiency should be somewhat higher or lower than 1,800 lb CO_2/MWh. If EPA does promulgate a higher or lower standard in either case, then EPA may revise the 600 lb CO_2/MWh amount accordingly.

enforceability of the 30-year averaging period, how we can ensure that the owner/operator will comply with the second phase of the standard, and what sort of compliance demonstrations are appropriate with such a long-term standard. We also solicit comment on whether this alternative compliance mechanism should automatically terminate in 2020 such that only facilities that commenced construction prior to 2020 would be able to use the 30-year average.

The EPA suggests that this 30-year averaging compliance option may be warranted for at least two reasons. First, it provides power companies with the option of building a coal-fired power plant in the near term and installing CCS at a later time when costs will likely be lower and further experience from demonstration projects will have been gained. The 30-year averaging period is sufficiently long to allow sources, before they install CCS, to benefit from the experience that will be gained from commercial-scale CCS demonstration projects operating over the next decade from a number of DOE-funded demonstration projects. A new coal- or pet coke-fired unit could operate for at least a decade before installing CCS and still have enough years operating at a controlled emission rate to reach a 1,000 lb CO_2/MWh standard on a 30-year basis. A second reason that this alternative may be practicable is that, even for sources installing and operating CCS at the beginning of a project, there may be startup issues (other than those related to the capture technology or the arrangements for sequestration). For instance, a company's ability to sequester CO_2 may be dependent upon construction by a third party of a pipeline that will be transporting the CO_2 to a site to be used for enhanced oil recovery or permanent sequestration. Because the owner or operator does not have direct control over this part of the project, there may be concerns that it will not be completed on time and that even after spending all of the money to construct a coal-fired unit capable of capture, it will have to remain non-operational for a period of time until the pipeline project or sequestration destination is completed. The 30-year averaging compliance option could provide flexibility to operate the unit until the pipeline was completed as long as the carbon capture system is designed to meet a rate sufficiently below 1,000 lb CO_2/MWh to allow for compliance with a 30-year averaging period. Such flexibility is likely to be most important for the first several CCS projects (i.e., ''first movers'') because of the complexity of integration of the technologies and the fact that the business model is new for the power sector. Because the policy purpose of this 30-year averaging compliance option is to leave open the option of building a coal-fired unit in the near term and installing CCS after several years or to allow for flexibility during startup of the system, a long-term averaging period is needed to allow time for such a unit to achieve the 1,000 lb CO_2/MWh level.

We note that under CAA section 111(b)(1)(B), ''the Administrator shall, at least every 8 years, review and, if appropriate, revise [the] standards [of performance] * * * ''. This review is required to take place in 2020, if not sooner. In the event that the EPA adopts the 30-year averaging compliance option, then at the time of the next required review, the EPA will evaluate the state of development or commercialization of CCS technologies and make a determination as to whether or not the 30-year averaging approach is still warranted for new sources. Because we expect CCS technology to advance significantly over the next several years, we believe that it may not be necessary to include this type of compliance option for a 30-year average the next time we review this NSPS. In light of this, we further solicit comment as to whether the 30-year averaging compliance option should automatically terminate in 2020, so that it would be available only for facilities that commenced construction prior to 2020.

We recognize that this compliance option, by authorizing sources to average the CO_2 emission level over a 30-year period, is unique. We recognize that the uniqueness of this approach may give rise to new issues concerning compliance and enforcement. We solicit comment on any practical difficulties in compliance and enforcement. Along these lines, although we propose that sources be required to retain records to demonstrate compliance with the emission limits for at least 30 years following the date of initial startup of the affected EGU, we solicit comment on the merits of extending this period to 50 years. As with the proposed standard of performance, no averaging or emissions trading among affected sources would be allowed for this 30-year averaging compliance option.

This 30-year averaging compliance option is available only to new coal- and pet coke-fired EGUs. We do not believe that it is necessary for NGCC units, as they should be able to meet the proposed performance with no need for add-on technology. We also solicit comment on the need to extend the applicability for the 30-year averaging compliance option to other fossil fuels beyond just coal and pet coke. We seek comment on all other aspects of this 30-year averaging compliance option.

C. What are the startup, shutdown, and malfunction requirements?

1. Startups and Shutdowns

The NSPS that the EPA is proposing in this action would apply at all times, including during startups and shutdowns. In establishing the level of the proposed NSPS, the EPA has taken into account startup and shutdown periods. The EPA is not proposing different standards for those periods.

To establish the proposed NSPS's output-based CO_2 standard, we accounted for periods of startup and shutdown by considering periods of part-load operation. As noted above, the proposed method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electrical energy output and useful thermal energy output, where applicable for CHP EGUs, over a rolling 12-month period. This averaging approach gives more weight to high-load hours and more accurately reflects overall environmental performance. In addition, because low-load hours do not factor as heavily into the calculated average, the impact of including periods of startup and shutdown is minimized when calculating emission rates.

We solicit comment on the alternative of requiring compliance through an annual (calendar year) average.

We propose that these same requirements for startups and shutdowns would apply to the 30-year averaging compliance option.

2. Malfunctions

The NSPS that the EPA is proposing in this action would apply at all times, including during malfunctions. Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. By contrast, malfunction is defined as a ''sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * * ''(40 CFR 60.2). The EPA has determined that CAA section 111 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 111 standards. Further, nothing in section 111 or in case law requires that the EPA anticipate and account for

the innumerable types of potential malfunction events in setting emission standards. *See, Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (DC Cir. 1978) (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.'')

Further, it is reasonable to interpret CAA section 111 as not requiring the EPA to account for malfunctions in setting emissions standards. For example, we note that section 111 provides that the EPA set standards of performance which reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. Applying the concept of ''the application of the best system of emission reduction'' to periods during which a source is malfunctioning presents difficulties. The ''application of the best system of emission reduction'' is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not ''reasonably'' foreseeable. *See, e.g., Sierra Club* v. *EPA,* 167 F.3d 658, 662 (DC Cir. 1999) (The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to ''invest the resources to conduct the perfect study.''). In addition, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with section 111 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR section 60.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.,* ''State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown'' (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983), which are both included in the docket for this rulemaking.) The EPA is therefore proposing to add to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. See 40 CFR 60.10042 (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense: The source must prove by a preponderance of the evidence that it has met all of the elements set forth in 60.10001. (See 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 60.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions ''[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *.'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 60.10001 and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that ''[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *.'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR part 22.77).

The EPA is including an affirmative defense in an attempt to balance a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that ''limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.'' 42 U.S.C. 7602(k) (defining ''emission limitation and emission standard''). *See* generally *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (DC Cir. 2008) Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief.[43] While ''continuous'' limitations, on the one hand, are required, there is also case law indicating that in many situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (DC Cir. 1973), the DC Circuit acknowledged that in setting standards under CAA section 111 ''variant provisions'' such as provisions allowing for upsets during startup, shutdown and equipment

[43] Note that the Ninth Circuit recently upheld EPA's decision to apply this affirmative defense approach to only actions seeking civil penalties, and not also to actions seeking injunctive relief. *Montana Sulfur & Chemical Co.* v. *EPA, No. 02–71657 (9th Cir. August 31, 2011) (slip op. at 456).*

malfunction ''appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force.'' *See* also, *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (DC Cir. 1973). Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments undermine the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating ''upsets beyond the control of the permit holder.'' *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). But *see, Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (DC Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission limitations are ''continuous'' as required by 42 U.S.C. 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

We propose that these same requirements for malfunctions would apply to the 30-year averaging compliance option; however, we take comment on whether it is appropriate to have an affirmative defense for the 30-year averaging portion of that compliance option, given that we would expect malfunctions to only impact shorter emissions limits, and the longer the compliance period, the less likely malfunction events are to impact a source's ability to meet the standard.

D. What are the continuous monitoring requirements?

The EPA is proposing that a CO_2 mass rate CEMS and the associated automatic data acquisition and handling system must be installed and operated in accordance with the requirements below.

1. Prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements consistent with the requirements in 40 CFR part 75.

2. Use all the data collected during all other required data collection periods in assessing the operation of the control device and associated control system.

3. Report any periods for which the monitoring system failed to collect required data.

4. Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments); failure to collect required data is a deviation of the monitoring requirements.

We propose that owners/operators would install the CEMS and complete the CEMS certification in accordance with the schedule required in 40 CFR part 75, section 75.4(b).

We also request comment on the appropriateness of applying the backup monitor requirements in 40 CFR part 75.10(e), the missing data procedures in 40 CFR part 75, sections 75.31 through 75.37, and appendix C for this proposed rule.

We propose that these same monitoring requirements would apply to the 30-year averaging compliance option.

E. What are the emissions performance testing requirements?

Consistent with the performance testing requirements in the CAA section 111 regulatory general provisions (40 CFR part 60.8) and CEMS certification requirements (40 CFR part 75.4(b)), we propose that owners/operators of a new unit, conduct an initial performance test to demonstrate compliance with the CO_2 emissions limits beginning in the calendar month following initial certification of the CO_2 and flow rate monitoring CEMS.

We propose that the initial performance test consist of collection of hourly CO_2 average concentration, mass flow rate (standard cubic feet per hour) recorded with the certified CO_2 concentration and flow rate CEMS and the corresponding electrical power generation data for all of the hours of operation for the first calendar year beginning on the first day of the first month following completion of the CEMS installation and certification. For all of the operating hours during each monthly period, including startup and shutdown, you would calculate compliance with the emissions limit by dividing the sum of the hourly CO_2 mass values by the sum of the hourly useful energy output produced over the first 12 months of data.

We propose that these same emissions performance testing requirements would apply to the 30-year averaging compliance option.

F. What are the continuous compliance requirements?

In this rulemaking, we propose that compliance with the applicable average CO_2 mass emissions rate (lb/MWh) must be calculated as a 12-month rolling average, updated monthly, using the reported hourly CO_2 average concentration and flow rate values from the certified CEMS data collected for the previous month's process operating days along with generation data tracked by the facility for the unit. We propose that compliance with the emissions limit must be calculated by dividing the sum of the hourly CO_2 mass emissions values by the sum of the useful energy output produced for each calendar month period and that the 12-month rolling average must be updated as the average of the previous 12 months' calculations. Affected sources will continue to be subject to the standards and maintenance requirements in the section 111 regulatory general provisions. 40 CFR part 60, subpart A.

We solicit comment on, in the alternative, an annual (calendar year) average emission limit, which would be calculated through comparable methodology as just described.

We propose that these same continuous compliance requirements would apply to the 30-year averaging compliance option.

G. What are the notification, recordkeeping, and reporting requirements?

In this rulemaking, the EPA is proposing that you, as the owner or operator of a new unit, must comply with the notification and recordkeeping requirements in the section 111 regulatory general provisions, 40 CFR part 60, subpart A, and need to report results of performance testing and excess emissions; as well as record and maintain hourly average CO_2 emissions concentration, hourly average flow rate, and hourly useful electrical generation. Note that the summary form identified as Figure 1 in 40 CFR part 60.7(d) will be revised to include CO_2 as a pollutant. We are also seeking comments on whether the EPA should require initial notification of compliance status reports. In most rules, an initial notification of compliance status report, where owners and operators of sources subject to a particular rule notify the EPA and State and Local Air Pollution Control Agencies that their source is subject to the rule and how they intend to comply with the rule, is required. Regulators find this information very helpful in implementing and enforcing particular rules. In this case, most, if not

all, of the sources that are potentially subject to this rule have already been identified because they are subject to other New Source Performance Standards and Part 75 Acid Rain provisions.

As part of an Agency-wide effort to facilitate reporting of environmental data and reports, we are requiring electronic reporting of selected reports, required by this regulation, to the EPA. We are proposing that owners and operators subject to this regulation must electronically submit excess emissions, continuous monitoring systems performance and-or summary reports required under section 60.7(c). Owners and operators would need to submit these reports to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed in the Central Data Exchange (CDX). The CDX is the EPA's portal for submitting and managing electronic environmental data and reports and is accessed at *www.epa.gov/cdx.* The CDX is needed to meet the EPA standards for electronic reporting set by the Cross-Media Electronic Reporting Rule. For more information, please see *http://www.epa.gov/cromerr/.* Owners and operators required to submit electronic reports would need to register to use the CDX and for the CEDRI node at *http://cdx.epa.gov/epa_home.asp.* Once a user has access to CDX and CEDRI, the owners and operators would use the subpart specific forms in CEDRI to enter the information for the 60.7(c) required reports.

In most New Source Performance Standards owners and operators are required to keep records of their reports on site for at least 2 years. Since the owner or operator would be submitting the data in these reports to be housed in CDX and WebFIRE, we are proposing to forgo recordkeeping requirements for those reports required to be submitted in proposed section 60.5555(a)(1). We believe that since the WebFIRE database is public that the need for recordkeeping onsite for certain information will not be needed as the information will be readily available for all stakeholders to access.

We are aware that owners or operators of many existing EGUs are required to submit some emissions data through the EPA Acid Rain Program's Emissions Collection and Monitoring Plan System (ECMPS) for SO_2, NO_X, CO_2, and other related data. We propose for affected sources to continue to use ECMPS with modifications to allow for collecting CO_2 mass emissions data and the CEMS relative accuracy reports proposed in this rule.

We request comment on these and other modifications to ECMPS appropriate for implementing this rule and any other EPA rules that apply to EGUs in order to streamline and focus all applicable emissions data reporting requirements. We request comment on modification of the ECMPS system to collect, track, and calculate CO_2 emissions rates based on hourly useful energy output for the unit. We also request comment on tracking and making use of useful steam data for new facilities.

We are also aware that owners or operators of existing units are required to submit electrical generation data according to procedures required by the DOE's Energy Information Administration (EIA) for its reports. We request comment on the appropriateness of using these electrical generation data in this proposed rule.

The EPA proposes that these same notice, recordkeeping, and reporting requirements would apply to the 30-year averaging compliance option. The EPA requests comment on whether any alterations or additions are appropriate for the notice, recordkeeping, and reporting requirements that would apply to the 30-year averaging compliance option. The EPA also requests comment on whether sources that utilize the 30-year averaging compliance option should include, as applicable requirements in their title V permits, a specific explanation of their compliance plan, including when CCS would be deployed, what capture rate(s) would be achieved, how the CO_2 would be sequestered, and whether the company anticipates receiving government financial assistance or other incentives for the CCS.

IV. Rationale for the Proposed Standards for New Sources

A. How did the EPA establish the emission limits?

1. Rationale for Proposing to Combine the Subpart Da Category and a Component of the Subpart KKKK Category into a New Category for Purposes of Regulating GHG Emissions

The EPA is proposing to create a new subpart in 40 CFR part 60 by combining the sources in subpart Da (the Da category) and a subset of the sources in subpart KKKK (the KKKK category)—stationary combined cycle units, but not stationary simple cycle units—for purposes of promulgating standards of performance for emissions of GHGs from new sources. This new subpart will be numbered TTTT. Consistent with standard practice and Executive Order 13563, and in particular its emphasis on ''the open exchange of information and perspectives'' and ''providing an opportunity for public comment on all pertinent parts of the rulemaking docket, including relevant scientific and technical findings'' and on consideration of alternatives, we invite comments on our decision to combine the two source categories.

At this time, the EPA is not proposing to subcategorize new sources and is not proposing to combine the Da category and components of the KKKK category for purposes of regulating criteria pollutants.

CAA section 111 provides legal authority for combining the categories into a new category. Clean Air Act section 111(b)(1)(A) provides:

> The Administrator shall, within 90 days after December 31, 1970, publish *(and from time to time thereafter shall revise)* a list of categories of stationary sources. He shall include a category of sources in such a list if in his judgment it causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

(Emphasis added.)

As quoted, this provision grants to the Administrator the authority to ''revise'' the list of categories. Combining categories, in whole or in part, is a form of ''revis[ing]'' the list of categories (along with taking other actions, such as adding more categories or delisting categories), and accordingly is authorized.

For three principal reasons, it is appropriate for the EPA to combine the Da category and the stationary combined cycle component of the KKKK category at this time for purposes of regulating GHGs. First, all of the plants covered by the new combined category (including fossil fuel-fired boilers, IGCC units and NGCC units) perform the same essential function, which is to provide generation to serve baseload or intermediate load demand. It is sensible to treat as part of the same category units that generate baseload or intermediate load electricity, regardless of their design or fossil fuel type.

Second, all newly constructed sources have options in selecting their design (although it is true that natural gas-fired plants are inherently lower emitting with regard to CO_2 than coal-fired plants. As a result, prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC unit. These two factors provide sufficient legal rationale for the EPA to combine the Da category and the combined cycle component of the KKKK category for purposes of

establishing a standard of performance for GHG emissions.

The agency has previously combined one type of baseload and intermediate load combined cycle unit (IGCC, previously covered under Subpart GG) with Da units for the purposes of setting a standard [40 CFR 60.41Da(b), Feb. 28, 2005]. This action now similarly combines another type of baseload and intermediate load combined cycle unit (NGCC, previously covered under Subpart KKKK) with Subpart Da units for the purposes of setting a standard.

A third factor lends additional support. Combining the categories does not raise adverse policy concerns. On the basis of comments made during the listening sessions, we anticipate that some commenters may question whether combining the categories and applying the NGCC standard to all new plants within the combined category may limit construction of new coal-fired power plants, and thereby have a disruptive effect on the electric power industry, increase electricity prices and/or have adverse implications for energy diversity in new generation. We do not believe that this action would have those effects. As discussed below, and importantly, economic models forecast no new construction of coal-fired generation without CCS through the analysis period, which extends until 2020 (when the standard will be revisited). Accordingly, economic conditions are expected to be the main driver precluding, or at least limiting, construction of coal-fired EGUs. Because of those economic conditions, there is a strong independent movement of power plants serving baseload generation toward NGCC. In light of that movement, it is appropriate for the EPA to focus on this technology in developing the standard, rather than subcategorizing and providing a separate standard for new coal units. *See Portland Cement Ass'n* v. *EPA,* 665 F.3d 177, 190 (D.C. Cir. 2011) (affirming the EPA's decision not to subcategorize in part because of ''the universal movement in the portland cement industry towards adoption of preheater/precalciner technology'').

Notwithstanding these points, we recognize the possibility that a limited amount of new coal-fired construction may nevertheless occur. Today's action would not foreclose construction of new coal-fired EGUs. Rather, the new coal-fired EGUs that may be expected to be built in the foreseeable future (and for reasons stated above, this is anticipated to be a relatively small number) may install CCS control equipment (if not at the time of construction, then not long thereafter). By doing so, they may achieve the same average CO_2 emission rate (at least over time) as a natural gas-fired combined cycle unit. It is reasonable to expect that some coal-fired power plants may be able to implement CCS at the present time, and thereby achieve the 1,000 lb CO_2/MWh standard immediately. As noted elsewhere, CCS has been demonstrated to be technologically achievable, and, even though it is costly, there are some State and Federal programs that can make CCS more affordable. Several power companies have announced plans to incorporate CCS at six already permitted coal-fired EGU construction projects in this country (as we discuss below in section V.B., concerning transitional sources). Programs exist that provide some funding for CCS through pilot or other demonstration programs, and we expect those to continue. In addition, we reasonably expect the costs of CCS to decline over time. As discussed below, we are not proposing that CCS does or does not qualify as the ''best system of emission reduction'' that ''has been adequately demonstrated'' for new coal-fired power plants. Rather, the feasibility of CCS and its availability for the limited amount of new coal-fired construction that may be expected, means that this action to combine the categories and establish the NSPS at the proposed 1,000 lb CO_2/MWh emission limit will not have notable adverse effects on new coal-fired construction or, therefore, on the electric utility industry, electricity prices, or energy diversity. We welcome public comments on this discussion.

On the other hand, at this time, we do not consider it appropriate to include simple cycle facilities as an affected source in the new 40 CFR part 60, subpart TTTT for GHG emissions from new facilities. The reason for this is that the function of a new simple cycle power plant is different than that of a new combined cycle plant or coal-fired plant. Combined cycle plants and coal-fired plants are typically designed to provide baseload or intermediate-load power, while simple cycle turbines are designed to provide peaking power. Because combined cycle power plants and coal-fired power plants both serve the same purpose and have design options to emit CO_2 at similar levels, we believe it is appropriate to combine them. Because peaking turbines operate less and because it would be much more expensive to lower their emission profile to that of a combined cycle power plant or a coal-fired plant with CCS, the EPA does not believe it is appropriate to include them in this source category.

As noted above, some commenters in the listening sessions did suggest that the EPA not combine the two source categories. The EPA has rejected that option for all the reasons outlined above: (1) Fossil-fuel-fired boilers, combined cycle natural gas units, and IGCC units all serve the same basic function, generating baseload or intermediate load power; (2) the proposed standards can be met by different types of units in the category (NGCC units or coal-fired units with CCS); and (3) it is consistent with industry trends (as further explained elsewhere in this notice: Due largely to current and projected gas and coal price trends, new fossil-fuel-fired builds are projected to be natural gas combined cycle units or coal-fired units with CCS supported by federal funding). There is an additional reason for rejecting the option of retaining (and establishing separate standards for) separate source categories. The EPA's analysis (in Section 5.10 of the RIA) suggests that over a wide range of market conditions, constructing a new unit that meets a limit of 1,000 lb CO_2/MWh instead of an advanced coal-fired unit without CCS would likely produce net social benefits. For all of these reasons, retaining separate source categories would be unlikely to generate substantial private cost savings, but at the same time, would create the risk of significantly higher GHG emissions and other air pollutants from some new units, resulting, in turn, in higher social costs.

By the same token, at this time, we do not consider it appropriate to combine the Da category and the combined cycle component of the KKKK category for any pollutants other than GHGs, that is, for criteria pollutants. This is because although coal-fired EGUs have an array of control options for criteria and air toxic air pollutants to choose from, those controls generally do not reduce their criteria and air toxic emissions to the level of conventional emissions from natural gas-fired EGUs.

2. Endangerment and Cause-or-Contribute-Significantly Finding

a. *Overview.* In today's rulemaking, we propose or solicit comment on alternative interpretations for whether section 111 includes prerequisites to rulemaking that involve an endangerment finding and a cause-or-contribute-significantly finding. By its terms, CAA section 111 provides that once the EPA lists a source category for regulation because the category causes or contributes significantly to air pollution that may reasonably be anticipated to endanger public health or

welfare, the EPA then establishes requirements for new sources in that source category. The EPA proposes to interpret these provisions so that it is authorized to promulgate the rulemaking proposed today because it has already determined that both the Da and KKKK source categories cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. The EPA solicits comment on interpreting CAA section 111 in the alternative so as to require (i) an endangerment finding for air pollution not specifically covered by the endangerment finding the EPA made when listing the source category, but that in this case, the EPA's 2009 Endangerment Finding for GHGs under Section 202(a) of the CAA (along with the EPA's 2010 denial of petitions to reconsider (2010 Reconsideration Denial)), fulfills that requirement; and (ii) a cause-or-contribute-significantly finding for air pollutants not specifically covered by the cause-or-contribute-significantly finding the EPA made when listing the source category, and that in this case, the large amounts of CO_2 emissions from power plants provide a compelling basis allowing the EPA to propose that finding. The EPA also solicits comment on another alternative, which is interpreting CAA section 111 so as not to require a specific endangerment finding or cause or contribute finding, but simply to require the EPA to establish a rational basis for regulating an air pollutant from a source category. In this case, the EPA's 2009 Endangerment Finding for GHGs and the 2010 denial of petitions to reconsider the Endangerment Finding, as well as the large amounts of CO_2 emissions from power plants, provide that rational basis. Finally, as an alternative for the basis for a rational basis determination, the 2010 and 2011 Assessment Reports from the National Academies confirm the Endangerment Finding and the denial of petitions to reconsider.

b. *Proposal:* Previous Source Category Findings Meet Any Endangerment Prerequisite to Regulation. In this rulemaking, the EPA proposes to interpret CAA section 111 so that we are not required, as a prerequisite to regulating CO_2 emissions from EGUs, to issue a new finding as to the health or welfare impacts of GHG air pollution or a finding as to the extent that affected sources contribute to that air pollution.

Clean Air Act section 111(b)(1)(A), by its terms, requires that the Administrator list a source category for regulation if the ''category * * * in [the Administrator's] judgment, * * * causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.'' Clean Air Act section 111(b)(1)(B) goes on to provide that after listing the source category, the EPA must promulgate regulations ''establishing federal standards of performance for new sources within such category.'' In turn, CAA section 111(a)(1) defines a ''standard of performance'' as a ''standard for emissions of air pollutants which reflects the degree of emission reduction which (taking into account * * * cost * * * and any nonair quality health and environmental impact and energy requirements) * * * has been adequately demonstrated.''

Thus, although CAA section 111 clearly requires the EPA to list a source category if its emissions contribute significantly to air pollution that endangers public health or welfare, and then to promulgate standards of performance for particular pollutants, section 111 does not by its terms require that the EPA make any endangerment finding with respect to those particular pollutants, or any cause-or-contribute-significantly finding with respect to the source category, at the time the EPA promulgates the standards of performance for those pollutants. The lack of any such requirement contrasts with (i) the definition of ''standard of performance,'' which specifically requires the EPA to consider ''*nonair* quality health and environmental impact,'' CAA section 111(a)(1) (emphasis added); and (ii) other CAA provisions that do require the EPA to make endangerment and cause-or-contribute findings for the particular pollutant that the EPA regulates under those provisions. *E.g.,* CAA sections 202(a)(1), 211(c)(1), 231(a)(2)(A).

Accordingly, under our proposal, once the EPA has listed a source category, and the EPA proceeds to regulate particular pollutants from that source category, CAA section 111 does not require that the EPA make an endangerment finding for the relevant air pollution or a cause-or-contribute-significantly finding for the relevant air pollutants from that source category. The fact that the EPA is, in this rulemaking, proposing to partially combine the Da and KKKK source categories does not alter this outcome. As noted above, under CAA section 111(b)(1)(A), the EPA may add a source category to the list of categories only after determining that the source category ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has previously determined that each of the Da and KKKK categories causes or contributes significantly to such air pollution. Combining the Da category and some of the sources in the KKKK category does not necessitate that the EPA make a new cause-or-contribute-significantly finding for the expanded Da category. This is because the EPA has already found that at least one component of the new category—the former Da sources—by itself causes or contributes significantly to such air pollution. There is no reason why this expansion of the Da category to include the pre-existing Da sources plus additional sources could be considered to contribute to such air pollution to an extent that is less than the contribution from the pre-existing Da sources alone. As a result, the new category must necessarily be considered to cause or contribute significantly to such air pollution.

In addition to proposing this interpretation, we also solicit comment on alternative interpretations under CAA section 111, including those described next.

c. *First Alternative Interpretation:* Endangerment Finding Prerequisite. We solicit comment on an alternative interpretation under which the EPA is required, as a prerequisite to promulgating standards of performance under CAA section 111(b), to have issued an endangerment finding specifically for the relevant air pollution and a cause-or-contribute-significantly finding specifically for the relevant source category and air pollutant. In particular, what would be the legal basis for such an interpretation?

Even if CAA section 111 is interpreted to require those findings, then, in a case in which the EPA did not make those findings under CAA section 111, it is the EPA's view that the EPA would satisfy the need for a CAA section 111 endangerment finding through an endangerment or comparable finding that the EPA made or that Congress adopted under any other provision of the CAA. For example, the EPA may regulate, under CAA section 111, (i) NAAQS pollutants because of the determinations the EPA made under CAA sections 108 and 109 and (ii) HAPs that Congress listed under CAA section 112(b)(1). It is the EPA's interpretation that once an endangerment or comparable finding is made with respect to the relevant air pollution under another CAA provision, regulation under CAA section 111 of source categories that cause or contribute significantly to that same air pollution may proceed without any need for the EPA to revisit or update that endangerment finding as part of the

CAA section 111 regulatory process. Instead, any concerns about the continued validity of that endangerment finding may be resolved through a petition to reconsider that finding under the applicable CAA provision.

Applying this alternative interpretation of CAA section 111 to this rulemaking, the 2009 Endangerment Finding for GHG air pollution fulfills any requirement under CAA section 111 that the EPA issue a finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare in order for the EPA to establish standards of performance for GHG emissions from EGUs. As discussed above, the EPA already issued this endangerment finding under CAA section 202(a)(1), as part of its process for promulgating the Light Duty Vehicle Rule.

The EPA recognizes that under this alternative interpretation, the EPA could be required to issue a cause-or-contribute-significantly finding for CO_2 emissions from the fossil fuel-fired EGUs, as a prerequisite to regulating such emissions under CAA section 111. Therefore, under this alternative interpretation, in today's rulemaking, the EPA proposes to find that CO_2 emissions from fossil fuel-fired EGUs cause or contribute significantly to the GHG air pollution. The EPA's basis for this proposed finding is, in part, that the large amounts of CO_2 emitted by fossil fuel-fired EGUs clearly exceed the low hurdle necessary for the cause-or-contribute-significantly finding. As noted above in Tables 2 and 3, fossil fuel-fired EGUs emit almost one-third of all U.S. GHG emissions, and constitute by far the largest single stationary source category of GHG emissions. Indeed, so great is the contribution of CO_2 air pollutants from EGUs to GHG air pollution, that it is simply not necessary in this rulemaking to determine thresholds for when a contribution may be considered to be a ''significant[]'' contribution. If it were necessary, the EPA proposes that a limited amount of contribution would meet that standard in light of the fact that GHG air pollution is caused by a large number of types of sources and that no one source category dominates the entire inventory.

d. *Second alternative interpretation:* Rational Basis Prerequisite. As a second alternative interpretation, the lack of any requirement in CAA section 111 addressing whether and how the EPA is to evaluate emissions of particular pollutants from sources in the listed source category as a prerequisite for regulation may be viewed as a statutory gap that requires a *Chevron* step 2 interpretation. In this case, the EPA is authorized to develop an interpretation that reasonably effectuates the purposes of CAA section 111. Under this alternative interpretation, the EPA must demonstrate a rational basis for controlling the emissions of the particular pollutants. That rational basis may consist of some type of factual showing that is consistent with the purposes of CAA section 111, but may be something short of an endangerment and a cause-or-contribute-significantly finding.

There are several options for the factual showings that comprise a rational basis. Under the first option, the EPA would be justified in the present case in taking action with respect to GHG air pollution because of the EPA's 2009 Endangerment Finding that GHG air pollution may reasonably be anticipated to endanger public health and welfare. The EPA issued that Endangerment Finding quite recently, in December, 2009, and by notice dated August 13, 2010, the EPA denied ten petitions to reconsider that Finding, an action that entailed further review of scientific information.

Under the second option, the EPA could conclude that the recent Endangerment Finding and denial of reconsideration, coupled with the even more recent assessments from the NAS, published in 2010 and 2011, which lend further credence to the science supporting the Endangerment Finding, suffice to provide a rational basis for promulgating regulations under CAA section 111 designed to address contributions to the GHG air pollution.

Under either of these options, the EPA would need to establish a rational basis for regulating CO_2 emissions from affected EGUs. The fact that affected EGUs emit almost one-third of all U.S. GHGs and comprise by far the largest stationary source category of GHG emissions, as discussed above, would readily provide such a rational basis.

3. Rationale for Emission Limits

a. *Few New Coal-fired Power Plants.* An important part of the basis for the EPA's proposal for new sources in this rulemaking is that all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future. Although a small number of new coal-fired power plants have been built recently, the industry generally is not building these kinds of power plants at present and is not expected to do so for the foreseeable future. The reasons include the current economic environment, which has lead to lower electricity demand, and competitive natural gas prices. Natural gas prices have stabilized over the past few years as new drilling techniques have brought additional supply to the marketplace. As a result, natural gas prices are expected to be competitive for the foreseeable future and utilities are likely to rely heavily on natural gas to meet new demand for electricity generation. On average, the cost of generation from a new NGCC power plant is expected to be lower than the cost of generation from a new coal-fired power plant.[44]

Other drivers that may influence decisions to build new power plants are State and Federal energy and tax policies. Many states have adopted renewable portfolio standards (RPS), which require that a certain portion of electricity come from renewable energy sources like solar or wind. The federal government has also adopted incentives for electric generation from renewable energy sources and loan guarantees for new nuclear power plants.

These economic, cost, and policy factors create an environment in which natural gas-fired power plants, renewable energy, and nuclear power are the forms of energy generation that are most often predicted to be built to meet new electricity demand over the coming years.

Various energy sector modeling efforts, including projections from both the EIA and the EPA, show results that are consistent with these findings. The Annual Energy Outlook (AEO) for 2011 shows a very modest amount of new coal-fired power coming online beyond 2012, although there are a number of coal-fired power plants that are currently under construction and expected to begin operation in the next year or two. According to the AEO 2011, the majority of new generating capacity will be either natural gas-fired or renewable, with some lesser amounts of nuclear power. The AEO 2011 is based on existing policy and regulations, such as state RPS programs and Federal tax credits for renewables.[45] The new generation that EIA does show coming on-line after 2012 fits into one of three categories: generation that is currently under construction, generation that will include CCS or industrial CHP. Units in the first group would not be subject to this rule because, since they have commenced construction, they are considered existing sources. Units in the second group would include either units in the transitional category or new

[44] Levelized Cost of New Generation in the Annual Energy Outlook 2011 *http://205.254.135.24/oiaf/aeo/electricity_generation.html.*

[45] *http://www.eia.gov/forecasts/aeo/chapter_legs_regs.cfm.*

units. In either case, they could be built consistent with this action. Units in the third group would not be subject to this rule because CHP units that generate primarily on-site power are not considered EGUs and are thus not affected by the rule.

The EPA modeling using the Integrated Planning Model (IPM), a detailed power sector model that the EPA uses to support power sector regulations, is keyed to the AEO in a number of respects and shows similar patterns of little future construction of new coal-fired power plants under the base case.[46] The EPA's projections from IPM can be found in the RIA.

As discussed below, the fact that the expected number of coal-fired power plants is so limited supports both (i) basing the standard of performance on NGCC, which is expected to be the most commonly built new fossil fuel-fired generating technology; and (ii) allowing 30-year averaging as an alternative compliance option for coal- and pet coke-fired power plants because CCS is feasible and sufficiently available for the few such plants expected, in light of the demonstration programs or other incentives available for CCS, coupled with the prospects that the costs of CCS will decline over time.

b. *Basis for the Proposed Standard of Performance.* In this section, we describe our basis for proposing a standard of 1,000 lb/MWh, and for taking comment on a range of 950 to 1,100 lb/MWh (430 to 500 kg/MWh). We first describe our method for calculating these levels of CO_2 emissions, and then note that several states are already requiring these levels of CO_2 emissions.

(1) Calculation of the Standard. For reasons explained below (see ''d. Legal Justification for the Standard of Performance and 30-year averaging compliance option''), a NGCC facility is the best system of emission reduction for new baseload and intermediate load EGUs. To establish an appropriate, natural gas-based standard, we reviewed the emissions rate of natural gas-fired (non-CHP) combined cycle facilities used in the power sector that commenced operation between 2006 and 2010 and that report complete generation data to EPA. Based on this analysis, nearly 95% of these facilities meet the proposed standards on an annual basis. These units represent a wide range of geographic locations (with differing elevations and ambient temperatures), operational characteristics, and sizes.

We are requesting comment on a range of 950 to 1,100 lb/MWh (430 to 500 kg/MWh) for the final rule. The upper limit would incorporate essentially all available new combined cycle designs and would have limited impact on improving efficiency of combined cycle facilities. This upper limit would also be consistent with standards promulgated by some states, as noted elsewhere. The stricter standard would in general eliminate designs without a steam reheat cycle and similar lower efficiency designs for use in electric-only generation, and could limit presently available options for generation below approximately 40 MW. However, an owner/operator of combined cycle facilities with higher heat rates could either implement CHP or integrated solar thermal for feedwater heating to achieve the proposed standard.

(2) States Implementing a Comparable Standard. Several states have recently established emission performance standards or other measures to limit emissions of GHGs from new EGUs that are comparable to the proposal in this rulemaking. For example, in September 2006, California Governor Schwarzenegger signed into law Senate Bill 1368. The law limits long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the California Energy Commission and the California Public Utilities Commission. The Energy Commission has designed regulations that establish a standard for new and existing baseload generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb CO_2/MWh.

In May 2007, Washington Governor Gregoire signed Substitute Senate Bill 6001, which established statewide GHG emissions reduction goals, and imposed an emission standard that applies to any baseload electric generation that commenced operation after June 1, 2008 and is located in Washington, whether or not that generation serves load located within the state. Baseload generation facilities must initially comply with an emission limit of 1,100 lb CO_2/MWh.

In July 2009, Oregon Governor Kulongoski signed Senate Bill 101, which mandated that facilities generating baseload electricity, whether gas- or coal-fired, must have emissions equal to or less than 1,100 lb CO_2/MWh, and prohibited utilities from entering into long-term purchase agreements for baseload electricity with out-of-state facilities that do not meet that standard. Natural gas- and petroleum distillate-fired facilities that are primarily used to serve peak demand or to integrate energy from renewable resources are specifically exempted from the performance standard.

c. *Basis for CCS as a Feasible Technology Option.* In this section, we describe the basis for our position that CCS is a feasible technology option for new coal-fired power plants because CCS is technically feasible and sufficiently available in light of the limited amount of new coal-fired construction expected in the foreseeable future. In brief, first, at present, CCS is technologically feasible for implementation at new coal-fired power plants and its core components (CO_2 capture, compression, transportation and storage) have already been implemented at commercial scale. Second, although the costs of CCS are presently high, we have reason to expect that the costs of CCS will decrease over time. This action will itself contribute to downward pressure on CCS costs by shifting the regulatory landscape towards CCS, consistent with the recent report by the Interagency Task Force on Carbon Capture and Storage, established by President Obama on February 3, 2010, which we describe below. Third, we expect construction of no more than a few new coal-fired power plants by 2020 and those plants may well be able to take advantage of demonstration programs or other sources of funding for CCS. Fourth, several states have set emission standards that will make implementation of CCS necessary for new coal-fired power plants, some projects that implement CCS or components of it are proceeding, and other CCS projects are in the planning stages.

(1) Technological Feasibility of CCS. The current state of affairs concerning CCS was described and analyzed by the Interagency Task Force on Carbon Capture and Storage, established by President Obama on February 3, 2010, co-chaired by the DOE and the EPA, and composed of 14 executive departments and federal agencies. The Task Force was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016. The Task Force found that, although early CCS projects face economic challenges related to climate policy uncertainty, first-of-a-kind technology risks, and the current high cost of CCS relative to other technologies, there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in

[46] *http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation.*

reducing GHG emissions. The Task Force also identified the need for comprehensive review of the overall environmental impacts of CCS.

(a) Capture and Compression Technologies and Costs. Capture of CO_2 from industrial gas streams has occurred since the 1930s using a variety of approaches to separate CO_2 from other gases. These processes have been used in the natural gas industry and to produce food and chemical-grade CO_2. Although current capture technologies are feasible, the costs of CO_2 capture and compression represent the largest stumbling block to widespread commercialization of CCS. Currently available CO_2 capture and compression processes are estimated to represent seventy to ninety percent of the overall CCS costs.[47]

In general, CO_2 capture technologies applicable to coal-fired power generation can be categorized into three approaches: [48]

- Pre-combustion systems are designed to separate CO_2 and H_2 in the high-pressure syngas produced at IGCC power plants.
- Post-combustion systems are designed to separate CO_2 from the flue gas produced by fossil-fuel combustion in air.
- Oxy-combustion uses high-purity O_2, rather than air, to combust coal and therefore produces a highly concentrated CO_2 stream.

Each of these three carbon capture approaches (pre-combustion, post-combustion, and oxy-combustion) is technologically feasible. However, each results in increased capital and operating costs and decreased electricity output (that is, an energy penalty), with a resulting increase in the cost of electricity. The energy penalty occurs because the CO_2 capture process uses some of the energy produced from the plant.

(b) Current Availability of Transportation and Sequestration. The remaining steps for CCS (i.e., pipeline transportation and storage), are also well established but less expensive than capture and compression.

Carbon dioxide has been transported via pipelines in the U.S. for nearly 40 years. Approximately 50 million metric tons of CO_2 are transported each year through 3,600 miles of pipelines. Moreover, a review of the 500 largest CO_2 point sources in the U.S. shows that 95 percent are within 50 miles of a possible geologic sequestration site,[49] which would lower transportation costs. For these reasons, the transportation component of CCS is not expected to be a significant stumbling block to the commercial availability of CCS in the future.

With respect to sequestration, globally, there are at least four commercial integrated CCS facilities sequestering captured CO_2 into deep geologic formations and applying a suite of technologies to monitor and verify that the CO_2 remains sequestered.[50] These four sites represent over 25 years of cumulative experience on safely and effectively storing anthropogenic CO_2 in appropriate deep geologic formations.[51] Estimates based on DOE studies indicate that areas of the U.S. with appropriate geology have a storage potential of 1,800 billion to more than 20,000 billion metric tons of CO_2 in deep saline formations, oil and gas reservoirs and un-mineable coal seams.[52] The U.S. experience with large-scale CO_2 injection, such as at enhanced oil and gas recovery projects, combined with ongoing research, development, and demonstration programs in the U.S. and throughout the world, provide confidence that the storage—along with capture, compression and transport—of large amounts of CO_2 can be achieved.

It should be noted that the EPA recently finalized two rules that aim to protect drinking water and track the amount of CO_2 that is sequestered from facilities that carry out geologic sequestration. The Underground Injection Control (UIC) Class VI rule, established under authority of the Safe Drinking Water Act, sets requirements to ensure that geologic sequestration wells are appropriately sited, constructed, tested, monitored, and closed in a manner that ensures protection of underground sources of drinking water.[53] The UIC Class VI regulations contain monitoring requirements to protect underground sources of drinking water, including the development of a comprehensive testing and monitoring plan. This includes testing of the mechanical integrity of the injection well, ground water monitoring, and tracking of the location of the injected CO_2 using direct and indirect methods. Projects are also required to do extended post-injection monitoring and site care to track the location of the injected CO_2 and monitor subsurface pressures until it can be demonstrated that underground sources of drinking water are no longer endangered. Subpart RR of the Greenhouse Gas Reporting Program, which was established under authority of the CAA and builds on UIC requirements, provides requirements for quantifying the amount of CO_2 sequestered by these facilities.[54] In addition, the EPA recently proposed a rule that would conditionally exclude CO_2 streams from the definition of hazardous waste under RCRA, where these streams are being injected for purposes of geologic sequestration, provided that they are managed in accordance with certain conditions.[55] That proposed rule is based upon the EPA's conclusion that the management of CO_2 streams, under the proposed conditions, does not present a substantial risk to human health or the environment, and was based upon a review of existing regulatory programs applicable to the transportation of CO_2 streams, and their injection into permitted UIC Class VI wells. Together, these actions help create a consistent national framework to ensure the safe and effective deployment of geologic sequestration.

(2) Expected reduction in CCS costs. Research is underway to reduce CO_2 capture costs and to improve performance. The DOE/National Energy Technology Laboratory (NETL) sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options that will dramatically lower the cost of capturing CO_2 from fossil-fuel energy plants compared to today's available capture technologies. The DOE/NETL estimates that using today's commercially available CCS technologies would add around 80 percent to the cost of electricity for a new pulverized coal (PC) plant, and around 35 percent to the cost of electricity for a new advanced

[47] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

[48] IPCC, 2005; DOE, 2007.

[49] JJ Dooley, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone (2006), Carbon Dioxide Capture and Geologic Storage: A Key Component of a Global Energy Technology Strategy to Address Climate Change. Joint Global Change Research Institute, Battelle Pacific Northwest Division. PNWD–3602. College Park, MD.

[50] These projects are: Sleipner in the North Sea, Snøhvit in the Barents Sea, In Salah in Algeria, and Weyburn in Canada.

[51] Dooley, J. J., *et al.* (2009). An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. U.S. Department of Energy, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[52] U.S. Department of Energy National Energy Technology Laboratory (2010). Carbon Sequestration Atlas of the United States and Canada, Third Edition.

[53] Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, Final Rule, 75 FR 77230 (Dec. 10, 2010).

[54] Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide, Final Rule, 75 FR 75060 (Dec. 1, 2010).

[55] Hazardous Waste Management System: Identification and Listing of Hazardous Waste: Carbon Dioxide (CO_2) Streams in Geologic Sequestration Activities, Proposed Rule, 76 FR 48073 (Aug. 8, 2011).

gasification-based (IGCC) plant. The CCS research, development and demonstration program is aggressively pursuing efforts to reduce these costs to a less than 30 percent increase in the cost of electricity for PC power plants and a less than 10 percent increase in the cost of electricity for new gasification-based power plants.[56] The large-scale CO_2 capture demonstrations that are currently planned and in some cases underway, under DOE's initiatives, as well as other domestic and international projects, will generate operational knowledge and enable continued commercialization and deployment of these technologies.

Gas absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry and to produce food and chemical grade CO_2. The advancement of amine-based solvents is an example of technology development that has improved the cost and performance of CO_2 capture. Most single component amine systems are not practical in a flue gas environment as the amine will rapidly degrade in the presence of oxygen and other contaminants. The Fluor Econamine FG process uses a monoethanolamine (MEA) formulation specially designed to recover CO_2 and contains a corrosion inhibitor that allows the use of less expensive, conventional materials of construction. Other commercially available processes use sterically hindered amine formulations (for example, the Mitsubishi Heavy Industries KS–1 solvent) which are less susceptible to degradation and corrosion issues. The DOE/NETL and private industry are continuing to sponsor research on advanced solvents (including new classes of amines) to improve the CO_2 capture performance and reduce costs.

Significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology. A significant body of literature suggests that the per-unit cost of producing or using a given technology declines as experience with that technology increases over time,[57] and this has certainly been the case with air pollution control technologies. Reductions in the cost of air pollution control technologies as a result of learning-by-doing, research and development investments, and other factors have been observed over the decades.

We expect that the costs of capture technology will follow this pattern. Rubin *et al.* assessed the historical rates of cost reductions achieved by other energy and environmental process technologies and then, by analogy, estimated future cost reductions that might be achieved by four types of new power plants employing CO_2 capture.[58] The results of the study suggested that total costs of CO_2 capture can be expected to decline by the following percentages: NGCC by 40 percent, PC by 26 percent, IGCC by 13 percent, and Oxyfuel by 13 percent after installation of the first 100 GW of capacity.

In a subsequent study, the model used in the initial study was extended with learning curves for several key performance variables, including overall energy loss in power plants, the energy required for CO_2 capture, the CO_2 capture ratio (removal efficiency) and the power plant availability. The model predicted continued reductions in cost with increased implementation.[59]

In addition, we note that the Administration's CCS Task Force report recognized that CCS would not become more widely available without the advent of a regulatory framework that promoted CCS or a strong price signal for CO_2. Today's action is an important component in developing that framework.

(3) Limited amount of construction of new coal-fired power plants; opportunities for CCS funding. A third factor that supports CCS as a feasible technology option is that through the IPM model period of up to 2020, we expect few, if any, new builds of coal-fired EGUs, beyond those that already have approved PSD permits. We also expect continued opportunities for financial support for some CCS projects through a variety of potential mechanisms such as direct grants, tax incentives and/or regulatory programs (e.g. Clean Energy Standards or guaranteed electricity purchase price agreements).[60] Accordingly, the few new coal-fired generation projects that may occur over this timeframe may well find that financial support for CCS is available.

(4) State Requirements for CCS; Projects and Permits for CCS. Several states have recently established requirements that new coal-fired EGUs must implement CCS, and a number of projects with CCS have been approved and/or are under construction.

In May 2007, Montana Governor Schweitzer signed House Bill 25, adopting a CO_2 emissions performance standard for electric generating units in the state. House Bill 25 prohibits the state Public Utility Commission from approving new electric generating units primarily fueled by coal unless a minimum of 50 percent of the CO_2 produced by the facility is captured and sequestered.

On January 12, 2009, Illinois Governor Blagojevich signed Senate Bill 1987, the Clean Coal Portfolio Standard Law. The legislation establishes emission standards for new power plants that use coal as their primary feedstock. From 2009–2015, new coal-fueled power plants must capture and store 50 percent of the carbon emissions that the facility would otherwise emit; from 2016–2017, 70 percent must be captured and stored; and after 2017, 90 percent must be captured and stored.

The following is a brief summary of currently operating or planned CO_2 capture or storage systems, including, in some cases, components necessary for coal-based power plant CCS applications.

AES's coal-fired Warrior Run (Cumberland, MD) and Shady Point (Panama, OK) power plants are equipped with amine scrubbers developed by ABB/Lummus. They were designed to process a relatively small percentage of each plant's flue gas. At Warrior Run, approximately 110,000 tonnes of CO_2 per year are captured, whereas at Shady Point 66,000 tonnes of CO_2 per year are captured. The CO_2 from both plants is subsequently used in the food processing industry.[61]

[56] DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap, U.S. Department of Energy National Energy Technology Laboratory, December 2010.

[57] These studies include John M. Dutton and Annie Thomas, ''Treating Progress Functions as a Managerial Opportunity,'' 2, 235–247; Dennis Epple, Linda Argote, and Rukmini Devadas, ''Organizational Learning Curves: A Method for Investigating Intra-plant Transfer of Knowledge Acquired Through Learning by Doing,'' Organizational Science, Vol. 2, No. 1, February 1991; International Energy Agency, Experience Curves for Energy Technology Policy, 2000; and Paul L. Joskow and Nancy L. Rose, ''The Effects of Technological Change, Experience, and Environmental Regulation on the Construction Cost of Coal-Burning Generating Units,'' RAND Journal of Economics, Vol. 16,Issue 1, 1–27, 1985. See discussion in ''The Benefits and Costs of the Clean Air Act from 1990 to 2020,'' U.S. EPA, Office of Air and Radiation, April 2011.

[58] Rubin, E.S.; Yeh, S.; Antes, M.; Berkenpas, M.; Davison, J.; ''Use of experience curves to estimate the future cost of power plants with CO_2 capture'', Intl. J. of Greenhouse Gas Control, 1, 188 (2007).

[59] Van den Broek, M.; Hoefnagels, R.; Rubin, E.; Turkenburg, W.; Faaij, A.; ''Effects of technological learning on future cost and performance of power plants with CO_2 capture'', *Progress in Energy and Combustion Science* 35 (2009) 457–480.

[60] See Center for Climate and Energy Solutions, ''Financial Incentives for CCS''—*http://www.c2es.org/sites/default/modules/usmap/pdf.php?file=8380.*

[61] Dooley, J.J., *et al.* (2009). An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. U.S.

At the Searles Valley Minerals soda ash plant in Trona, CA, approximately 270,000 tonnes of CO_2 per year are captured from the flue gas of a coal power plant via amine scrubbing and used for the carbonation of brine in the process of producing soda ash.[62]

A pre-combustion Rectisol® system is used for CO_2 capture at the Dakota Gasification Company's synthetic natural gas production plant located in North Dakota, which is designed to remove approximately 1.6 million tonnes of CO_2 per year from the synthesis gas. The CO_2 is purified, transported via a 200-mile pipeline, and injected into the Weyburn oilfield in Saskatchewan, Canada.

In September 2009, American Electric Power Co. (AEP) began a pilot-scale CCS demonstration at its Mountaineer Plant in New Haven, WV. The Mountaineer Plant is a 1,300 MWe coal-fired unit that was retrofitted with Alstom's patented chilled ammonia CO_2 capture technology on a 20 MWe portion, or ''slipstream'', of the plant's exhaust flue gas. In May 2011, Alstom Power announced the successful operation of the chilled-ammonia CCS validation project. The AEP–Alstom project, the world's first facility to both capture and store CO_2 from a coal-fired power plant, represents a successful scale-up of ten times the size of previous field pilots (e.g., at We Energies Pleasant Prairie). The demonstration achieved capture rates from 75 percent (design value) to as high as 90 percent, produced CO_2 at purity of greater than 99 percent, with energy penalties within a few percent of predictions. The facility reported robust steady-state operation during all modes of power plant operation including load changes, and saw an availability of the CCS system of greater than 90 percent.

AEP, with assistance from the DOE, had planned to expand the slipstream demonstration to a commercial scale, fully integrated demonstration at the Mountaineer facility. The commercial-scale system was designed to capture at least 90 percent of the CO_2 from 235 MW of the plant's 1,300 MW total capacity. Plans were for the project to be completed in four phases, with the system to begin commercial operation in 2015. However, in July 2011, AEP announced that it is terminating its cooperative agreement with the DOE and placing its plans to advance CO_2 capture and storage technology to commercial scale on hold, citing the current uncertain status of U.S. climate policy and the continued weak economy as contributors to the decision.

Oxy-combustion of coal is being demonstrated in a 10 MWe facility in Germany. The Vattenfall plant in eastern Germany (Schwarze Pumpe) has been operating since September 2008. It is designed to capture 70,000 tonnes of CO_2 per year.

In June 2011, Mitsubishi Heavy Industries, an equipment manufacturer, announced the successful launch of operations at a 25 MW coal-fired carbon capture facility at Southern Company's Alabama Power Plant Barry. The demonstration is planned to capture approximately 150,000 tons of CO_2 annually at a CO_2 capture rate of over 90 percent. The captured CO_2 will be permanently stored underground in a deep saline geologic formation.

Southern Company has begun construction of Mississippi Power Plant Ratcliffe (formerly the Kemper County IGCC Project). Plant Ratcliffe is a 582 MW IGCC plant that will utilize local Mississippi lignite and include pre-combustion carbon capture to reduce CO_2 emissions by 65 percent. Operation is expected to begin in 2014. The CO_2 captured from Plant Ratcliffe will be used for enhanced oil recovery (EOR) in the Heidelberg Oil Fields in Jasper County, MS.

The Texas Clean Energy Project, a 400 MW IGCC facility located near Odessa, TX will capture 90 percent of its CO_2, which is approximately 3 million tonnes annually. The captured CO_2 will be used for EOR in the West Texas Permian Basin. (Additionally, the plant will produce urea and smaller quantities of commercial-grade sulfuric acid, argon, and inert slag, all of which will also be marketed.) Construction is expected to begin in 2012.

d. Legal Justification for the Standard of Performance and 30-year Averaging Compliance Option. This section describes our legal justification for proposing that new affected facilities in the TTTT category—which combines the Da and part of the KKKK categories—(i) must limit their CO_2 emissions to 1,000 lb CO_2/MWh, which an affected facility could achieve by constructing a NGCC unit or by constructing a coal-fired boiler that implements CCS immediately; or (ii) in the case of a coal- or pet coke-fired power plant, may either meet the 1,000 lb CO_2/MWh standard or implement an 30-year averaging compliance option that allows an affected facility to meet an initial CO_2 emission limit of 1,800 lb CO_2/MWh (gross), and then—through the implementation of CCS—meet the 1,000 lb CO_2/MWh standard, on a time-averaged basis, over no longer than a 30-year period.

(1) Legal Justification for the Standard of Performance. The EPA proposes that the emission limit of 1,000 lb CO_2/MWh meets the requirements for a ''standard of performance'' applicable to new sources under CAA section 111(b)(1)(B). The term ''standard of performance'' is defined under CAA section 111(a)(1) as follows:

> Definitions. For purposes of this section: (1) The term ''standard of performance'' means a standard for emissions of air pollutants which reflects 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.

We apply this definition, in effect, from the bottom up. That is, first, we determine the ''best system of emission reduction which (taking into account * * * cost [and other factors]) the Administrator determines has been adequately demonstrated.'' For EGUs, that is a NGCC facility, for reasons discussed below. Then, we calculate the ''degree of emission limitation achievable through the application of'' such best system; and after that, we formulate ''a standard for emissions of air pollutants which reflects'' that degree of emission limitation. This standard is 1,000 lb of CO_2/MWh. These analytical steps are also discussed further below.

In determining the ''best system of emission reduction'' for this category of boilers and combined cycle units, we considered a range of natural gas-fired and coal-fired generation technologies, with available controls. We considered modern supercritical and ultra-supercritical coal-fired boilers. This technology is available—it is currently deployed in Europe and is now being widely deployed in Asia (especially China)—and it offers much more efficient operation than the subcritical boilers that have more often been constructed in the U.S. These supercritical and ultra-supercritical boilers have CO_2 emissions of approximately 1,800 lb/MWh and provide the lowest overall costs for conventional coal-based electricity. We also considered new IGCC, or ''coal gasification'' facilities, which can have CO_2 emissions levels very similar to those of ultra-supercritical coal-fired units—albeit at a higher price.

We also considered natural gas-fired boilers which have CO_2 emissions of approximately 1,350 lb/MWh, obviously

DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[62] IEA (2009a), World Energy Outlook 2009, OECD/IEA, Paris.

much lower than the advanced coal-fired or coal gasification technologies. However, it seems unlikely that utilities would choose a natural gas-fired boiler as the generation technology of choice when NGCC is a much more efficient, less expensive, and more widely used technology.

We propose that a NGCC facility is the best system of emission reduction for two main reasons. First, natural gas is far less polluting than coal. Combustion of natural gas emits only about 50 percent of the CO_2 emissions that combustion of coal does per unit of energy generated. Second, new natural gas-fired EGUs are less costly than new coal-fired EGUs, and as a result, our IPM model projects that for economic reasons, natural gas-fired EGUs will be the facilities of choice until at least 2020, which is the analysis period. Indeed, those models do not project construction of *any* new coal-fired EGUs during that period that would not comply with the proposed standard. This state of affairs has come about primarily because technological development and discoveries of abundant reserves have caused natural gas prices to decline precipitously in recent years and have secured those relatively low prices for the near-future. Importantly, because the IPM modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance in today's rulemaking—which is based on the emission rate of a new NGCC unit—does not add costs. In addition, compared to coal-fired EGUs, natural gas-fired EGUs have fewer nonair quality health and environmental impacts.

Essentially because natural gas generation is cleaner and cheaper than coal, natural gas-fired EGUs qualify as 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.''

We recognize that today's proposed approach of combining the Da category and a portion of the KKKK category, and applying as the standard of performance the rate that natural gas-fired EGUs can meet, represents a departure from prior agency practice. We consider this departure warranted in light of both the emissions benefits and the changed economic circumstances, notably the lowered prices of natural gas due to technological development and recent discoveries that have boosted recoverable reserves. We are aware that in theory, those economic circumstances could change and if they do, then a change in the standard of performance may be warranted. In this regard, we note that CAA section 111(b)(1)(B) requires that the EPA ''shall, at least every 8 years, review and, if appropriate, revise [the] standards [of performance].'' This 8-year review cycle provides a mechanism for the EPA to assure that the standard of performance for any particular source category continues to reflect the ''best system.''

(2) Legal Justification for the 30-year Averaging Compliance Option. Although the IPM model projects that for economic reasons, new coal- or pet coke-fired EGUs will not be built in the foreseeable future (beyond early CCS projects), we recognize that in a few instances, owners or operators may in fact seek to build coal- or pet coke-fired EGUs. As discussed in detail below, those owners or operators could avail themselves of CCS as a 30-year averaging compliance option. In addition, today's proposed rulemaking offers flexibility for CCS installation: The owners or operators could (i) achieve the supercritical efficiency level for an initial period (e.g., up to the first 10 years), and (ii) after that, implement CCS so as to achieve a 600 lb CO_2/MWh rate on a 12-month annual average during the latter period (i.e., the back 20 years) and thereby achieve the 1,000 lb CO_2/MWh rate on an average annual basis over the 30-year period. The alternative compliance option could also allow them to install and operate CCS much earlier and use the 10-year period to address any startup challenges related to being an early adopter of the technology.

Because CO_2 is long-lived in the atmosphere, the 30-year averaging period, as structured, with shorter term compliance requirements, is not expected to have a different impact on climate compared to meeting the standard of performance.

(a) CCS. The significance of CCS as a compliance alternative is several-fold. As a practical matter, it offers a vehicle for the construction of new coal-fired EGUs in those few instances in which owners or operators decide to construct such EGUs, notwithstanding the underlying economics. Also, it offers a vehicle for the continued scaling of CCS, a process that can be expected to lower the costs of CCS in the future. In addition, this compliance alternative provides further support for the reasonableness of the EPA's proposals in this rulemaking to combine the Da category and a portion of the KKKK category and to determine that a NGCC facility is the ''best system of emission reduction.'' This is because this compliance alternative, by providing a vehicle for new coal-fired power plant builds, would minimize any disruptions that the EPA's proposals might, at least in theory, otherwise entail to the power plant industry.

CCS as a compliance alternative does not achieve these goals by necessarily qualifying, under the CAA section 111(a)(1) definition of ''standard of performance,'' as the ''best system of emission reduction which (taking into account cost [and other factors]) the Administrator determines has been adequately demonstrated.'' Instead, this compliance alternative is feasible and sufficiently available for the limited amount of new coal-fired construction that is expected, whether or not it would qualify as the ''best system.''

First, it is reasonable to expect that some coal-fired power plants may be able to implement CCS at the present time, and thereby achieve the 1,000 lb CO_2/MWh standard immediately. As noted elsewhere, CCS has been demonstrated to be technologically achievable, and, even though it is costly, there are some state and Federal subsidy programs that can make CCS more affordable, particularly in tandem with use of captured CO_2 for enhanced oil recovery, and those programs may be sufficient for the very few new coal-fired plants that are expected to be constructed in the foreseeable future. Some of these programs are discussed above.

We note that the need for governmental subsidies to reduce the costs of CCS is hardly unique in the electricity generation sector. Each of the major types of energy used to generate electricity has been or is currently supported by some type of government subsidy—such as tax benefits, loan guarantees, low-cost leases, or direct expenditures—for some aspect of development and utilization, ranging from exploration to control installation. This is true of fossil fuel-fired; as well as nuclear-, geothermal, wind-, and solar-generated electricity. These subsidies have been designed to overcome cost barriers to the utilization of the energy. In this context, the need for subsidies for CCS to overcome cost barriers does not mean that CCS cannot be considered an alternative compliance method in this rulemaking.

Second, it is reasonable to expect that some coal-fired power plants may be able to implement the supercritical efficiency standard for an initial period of time (the first 10 years) and then implement CCS and achieve lower 12-month annual average rates after that, so that the source achieves the 1,000 lb CO_2/MWh standard on average over the

30-year period following construction.[63] This is because, again, CCS is feasible and can be expected to be sufficiently available—in light of continued subsidies and lower future costs—in light of the limited demand.

Third, although we do not propose that the 30-year averaging compliance option meets the definition of the ''best system of emission reduction [(BSER)] * * * adequately demonstrated,'' under CAA section 111, we note that identifying CCS as a compliance option based in part on the expectation that CCS will cost less in the future is consistent with the section 111 requirements for determining the BSER adequately demonstrated. In determining what emissions controls qualify as the BSER adequately demonstrated—which must take costs into account—the EPA is authorized under CAA section 111 to anticipate that technology that is costly at present will come down in price in the future. It is clear from the legislative history of section 111 and relevant case law that the EPA may anticipate future developments—as long as supported by an adequate record—in determining whether a particular system of emission reduction is the BSER adequately demonstrated. The Senate Committee Report to the 1970 CAA Amendments, which first enacted CAA section 111, made clear that the EPA may anticipate future developments in determining the BSER adequately demonstrated:

> As used in this section, the term ''available control technology'' is intended to mean that the Secretary should examine the degree of emission control that has been or can be achieved through the application of technology which is available *or normally can be made available. This does not mean that the technology must be in actual, routine use somewhere.* It does mean that the technology must be available at a cost *and at a time* which the Secretary determines to be reasonable. The implicit consideration of economic factors in determining whether technology is ''available'' should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

Sen. Rep. 91–1196 at 16 (emphasis added). As quoted, this statement makes clear that a standard of performance may be based on a technology that is not ''in actual routine use somewhere,'' but that ''normally can be made available.'' Moreover, the technology need not be available until ''a time which the Secretary determines to be reasonable.'' *Id.*

In addition, the D.C. Circuit has been explicit that in setting a CAA section 111 standard of performance, the EPA may make reasonable projections of what technology will be available to the regulated industry in the future. The Court stated, in *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973):

> We begin by rejecting the suggestion of the cement manufacturers that the Act's requirement that emission limitations be ''adequately demonstrated'' necessarily implies that any cement plant now in existence be able to meet the proposed standards. *Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present,* since it is addressed to standards for new plants—old stationary source pollution being controlled through other regulatory authority. It is the ''achievability'' of the proposed standard that is in issue. * * * The * * * standard is analogous to the one examined in *International Harvester* * * *. *The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on ''crystal ball'' inquiry.*[64]

Id. at 391 (emphasis added). Again, although these statements in the legislative history and case law are in the context of establishing the basis for a standard of performance, the same principle –- that the EPA may reasonably project the path of technological development –- supports treating CCS as a compliance alternative.

Although, for the reasons noted above, we do expect the costs of CCS to decline, we recognize that the amount of the decrease is uncertain. Even so, the presence of cost uncertainty by itself does not mean that prospective power plants cannot be expected to adopt the 30-year averaging compliance option. We note that prospective power plants face significant cost uncertainties in any event.

For example we note that recently, several owner/operators have announced that they do not intend to construct coal-fired power plants without CCS. They have explained that they anticipate more widespread CO_2 control requirements in the future, so that constructing coal-fired plants at this time without CCS could leave them subject to liability for high retrofit control costs in the future. This sentiment indicates that some sources may avail themselves of the 30-year averaging compliance option.

The inclusion of a 30-year averaging compliance option has precedent in EPA rulemaking under the CAA. In the past, the EPA has promulgated rules that adopt an emission limit based on a particular technology (such as, in the present rulemaking, NGCC), but has supported that action on grounds that sources have compliance alternatives, even though higher priced. See ''Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone: Final Rule'' 63 FR 57356, 57378 (Oct. 27, 1998) (in the rule that became known as the ''NO_X SIP Call,'' the EPA based NO_X emission limits that states were required to meet on the assumption that states could adopt specified control measures that were ''highly cost-effective,'' but the EPA identified other control measures that, even though not as cost-effective, the states could adopt instead).

(b) 30-year Period. We propose a 30-year period because (i) we generally expect that ten years provides sufficient time either for owners/operators who are interested in considering cost improvements that occur as a result of the lessons learned from early adopters, or provides early adopters sufficient time to address any startup challenges; and (ii) as noted above, 30 years provides enough time for sources to achieve the 1,000 lb CO_2/MWh emission limit following an elevated level of emissions over the first 10-year period.

(c) Supercritical Efficiency Level. According to the Department of Energy Cost and Performance Baseline for Fossil Energy Plants reports, the use of supercritical steam is the most cost effective option for new conventional coal-fired generation and results in the lowest overall costs. In addition, the increased efficiency results in reduced cooling water requirements and reduced environmental impacts associated with coal mining, delivery, and handling. Therefore, considering the benefits and minimal, if any, cost of using supercritical steam conditions, as opposed to subcritical steam conditions, we have concluded that an annual standard based on the best performing conventional coal-fired generation is appropriate.

There are a dozen bituminous-fired and 2 subbituminous-fired EGUs that have demonstrated the proposed annual standard is achievable on a long term basis. Furthermore, we have concluded that with coal drying technology, which is being used on a number of power plants today, the annual standard is achievable by a wide range of units

[63] Note that under today's proposed rulemaking, the 30-year averaging proposal is associated only with the implementation of CCS at new coal- or pet coke-fired EGUs. This proposal does not allow 30-year averaging for any other purpose.

firing a variety of coal types, including lignites. There are multiple vendors that offer processes to upgrade lignites to heating values that are equal to or greater than those of subbituminous coals. The best performing subbituminous-fired EGU has maintained a 12-month emissions rate of 1,730 lb CO_2/MWh. A new EGU using a similar design would be able to burn upgraded lignite and be in compliance with the proposed annual standard.

We solicit comment on all aspects of the alternative compliance option, including the 30-year averaging period we propose in this action. Although we are not proposing that CCS, including the 30-year averaging compliance option, does or does not qualify as the BSER adequately demonstrated, we also solicit comment on that issue.

B. How did the EPA determine the other requirements for the proposed standards?

1. Compliance Requirements

The proposed compliance requirements, to the extent possible, incorporate monitoring already being performed as part of existing part 60 and part 75 requirements.

In addition, we intend to recognize the environmental benefit of electricity generated by CHP facilities to account for the increased end use efficiency resulting from avoided transmission and distribution losses. Actual line losses vary from location to location, but we intend to assume a benefit of 5 percent avoided transmission and distribution losses when determining the electric output for CHP facilities. This provision would be restricted to facilities where the useful thermal output is at least 20 percent of the total output.

We also propose to base compliance requirements on a 12-month rolling average basis. The variability in GHG emissions rates is such that establishing a shorter averaging period would necessitate establishing a standard to account for the conditions that result in the lowest efficiency and therefore the highest GHG emissions rate. A 12-month rolling average accounts for variable operating conditions, allows consistent emissions rate averaging, allows for a more protective standard and decreased compliance burden, and simplifies compliance for state permitting authorities. Because the 12-month rolling average can be calculated each month, this form of standard makes it possible to assess compliance and take any needed corrective action on a monthly basis. The EPA proposes that it is not necessary to have a shorter averaging period for CO_2 from these sources because the effect of GHGs on climate change depends on global atmospheric concentrations which are dependent on cumulative total emissions over time, rather than hourly or daily emissions fluctuations or local pollutant concentrations.

Even so, we solicit comment on, in the alternative basing compliance requirements on an annual (calendar year) average basis.

V. Requirements for Modifications, Transitional Sources, Reconstructions

A. Requirements for Modifications

1. Overview

Under CAA section 111, existing sources are treated as new sources if they undertake ''modification[s],'' which are generally defined as physical or operational changes that increase emissions. CAA section 111(a)(2) and (4). The EPA's regulations exempt certain types of changes from the definition of modification. 40 CFR 60.14(e). Available information does not provide an adequate basis for the EPA to develop proposed standards of performance for modifications. Our base of knowledge concerning NSPS modifications has depended largely on the enforcement actions brought against power plants and on self-reporting by power plants. Over the lengthy history of the NSPS program, those have been too few in number to allow us to develop a sufficiently robust base of knowledge to propose a standard of performance for NSPS modifications for GHGs at this time.

We note that the types of projects that these EGUs are most likely to undertake that could increase GHG emissions are projects that put on pollution controls required under other CAA provisions and that emit CO_2 as a byproduct, and those types of projects are specifically exempted from the definition of ''modifications'' under 40 CFR 60.14(e)(5). In addition, based on past experience, we expect that actions that do constitute modifications to be from different types of sources and to take different forms. In light of this, the EPA does not have sufficient information to develop standards of performance for modifications, and therefore the EPA is not proposing any standards for modifications. As a result, EGUs that undertake pollution control projects or other physical or operational changes would continue to be treated as existing sources.

2. Statutory and Regulatory Requirements

Clean Air Act section 111(b)(1)(B) requires the EPA to promulgate ''standards of performance'' for ''new sources'' within source categories. For certain pollutants, CAA section 111(d)(1) requires the EPA to prescribe regulations for state plans covering ''existing source[s]'' in a category regulated for that pollutant under section 111(b). Clean Air Act section 111(a)(2) defines a ''new source'' as ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.'' Clean Air Act section 111(a)(6) defines an ''existing source'' as ''any stationary source other than a new source.'' Clean Air Act section 111(a)(4) defines ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.''

The EPA's regulations provide that under CAA section 111(a)(4), for purposes of determining whether an existing electric utility steam generating unit undertakes a modification, a physical or operational change is treated as increasing emissions only when it increases the ''maximum hourly emissions'' above the ''maximum hourly emissions achievable'' at the unit. 40 CFR 60.14(h). In addition, the EPA's regulations exempt certain physical or operational changes from the definition of modification. 40 CFR 60.14(e)(5). The exemptions include pollution control projects:

> (e) The following shall not, by themselves, be considered modifications * * *:
>
> * * * * *
>
> (5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

40 CFR 60.14(e)(5). Thus, the EPA's current regulations define a modification as a physical or operational change that increases an existing affected EGU's maximum achievable hourly rate of emissions, but specifically exempt from that definition pollution control projects, which are projects that entail the installation of pollution control equipment or systems.

3. The EPA's Proposed Course of Action

We expect EGUs to undertake changes in the foreseeable future that would increase their maximum achievable hourly rate of CO_2 emissions for

purposes of the NSPS. We expect that most of those actions would constitute pollution control projects. In many cases, those projects would involve the installation of add-on control equipment required to meet CAA requirements for conventional air pollutants. We expect that these increases in CO_2 emissions would occur as a chemical byproduct of the operation of the control equipment, and would be small. In other cases, those projects will involve equipment changes to meet the requirements of this rulemaking and that may have the effect of increasing the sources' maximum hourly achievable emission rate, even while decreasing actual emission rate. Because such actions would be treated as pollution control projects under the EPA's current NSPS regulations, they would be specifically exempted from the definition of modification.

Aside from pollution control projects, in the past, there have also been, as noted, a limited number of instances, on an annual basis, in which power plants have undertaken actions that should be treated as NSPS modifications. The sources that took these actions vary widely, one from another, depending on, among other things, size, fuel type, and physical plant configuration. The diversity of sources undertaking modifications has reflected the diversity among power plants as a whole. Moreover, the types of modifications they have undertaken have also varied widely.

Because of the limited number of modifications, their disparate nature, and the disparate type of sources, we do not at present have an adequate base of information to propose standards of performance for modifications. For example, we do not have adequate information as to the types of physical or operational changes sources may undertake or the amount of increase in CO_2 emissions from those changes. Nor do we have adequate information as to the types of control actions sources could take to reduce emissions, including the types of controls that may be available or the cost or effectiveness of those controls. The most likely candidates for control actions would be efficiency measures and we do not have adequate information as to the types of sources and types of changes at issue that could provide the basis for a proposal for efficiency measures. If there were a more robust set of data on facilities of a particular type undertaking NSPS modifications of a particular kind, the EPA may be able to develop a standard of performance for that type. But, as noted, that is not the case here.

As a result, in this action, the EPA is not proposing standards of performance for NSPS modifications for GHGs. The EPA is soliciting comment on the types of sources that may be expected to undertake modifications, the types of modifications, the types of control measures, and all other aspects of this issue. This solicitation of comment is in the nature of an advance notice of proposed rulemaking. If we receive sufficient additional information, we may issue a proposal for modifications in the future. However, to reiterate, we are not proposing any standards of performance for these modifications at this time. Accordingly, the EPA does not expect to promulgate any standards of performance for modifications when it takes final action on this rulemaking.

The definitional provisions of CAA section 111, quoted above, make clear that a stationary source that undertakes construction or modification is considered a ''new source'' only if there is a proposed or final ''standard of performance under this section which will be applicable to such source.'' CAA section 111(a)(2). Accordingly, if there is no proposed or promulgated standard of performance applicable to a particular source, then the source cannot be considered a ''new source'' and therefore will not be subject to any standards of performance we finalize for new sources.

Further, under the definitional provisions, any source that is not a ''new'' source is an ''existing source.'' CAA section 111(a)(6). Therefore, affected EGUs that undertake NSPS modifications for GHGs will continue to be treated as existing sources. Although modified sources would not be subject to the 1,000 lb CO_2/MWh standard for new sources, the EPA anticipates that modified sources would become subject to the requirements the EPA would promulgate at the appropriate time, for existing sources under 111(d). It is important to note that at the same time that the EPA promulgated the pollution control provision in the EPA's regulations under CAA section 111, the EPA promulgated a similar provision in EPA's NSR regulations. The DC Circuit, in *New York* v. *EPA,* 413 F.3d 3, 40 (DC Cir. 2005), vacated the NSR pollution-control-project exemption. Because of the similarities between the NSR and the section 111 pollution control project regulatory provisions, the Court's vacatur of the NSR regulatory provision may call into question the continued validity of the section 111 regulatory provision. As a result, we are soliciting comment on whether this exemption from the definition of ''modification'' for pollution control projects, under 40 CFR 60.14(e)(5), continues to be valid or not, and what course of action, if any, would be appropriate for the EPA to take.

B. Requirements for Transitional Sources

1. Overview

In this action, the EPA is not proposing a standard of performance for transitional sources. We define these sources as coal-fired power plants that, by the date of this proposal, have received approval for their PSD preconstruction permits that meet CAA PSD requirements (or that have approved PSD permits that expired and are in the process of being extended, if those sources are participating in a Department of Energy CCS funding program), and that commence construction within a year of the date of this proposal. For convenience, we refer to the new sources for which we are proposing a standard of performance as non-transitional sources.

Transitional sources are a distinct set of sources with unique circumstances.[65] We have identified 15 proposed sources that may qualify as transitional sources based on the above criteria. These proposed sources differ considerably one from another. They range in size from as small as 80 megawatts (MW) to as large as 1320 MWs; they will burn different fuels: Conventional coal, waste coal, or petcoke; and they will use different technologies: Circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), supercritical pulverized coal, or sub-critical pulverized coal. Recent industry practice raises the probability that no more than a few of these 15 proposed sources will in fact be constructed.

We recognize that by the date of this proposal, some of the 15 proposed sources may have incurred substantial sunk costs and may have progressed in their preconstruction planning to the point where they are poised to commence construction in the very near future. Under these circumstances, the 1,000 lb CO_2/MWh standard of performance that applies to non-transitional sources would not be appropriate for these proposed sources. As noted, that standard is based on natural gas combined cycle (NGCC) as the ''best system of emission reduction * * * adequately demonstrated'' because NGCC is the least expensive

[65] Nothing in this discussion of the unique circumstances of transitional sources facing new GHG requirements should be interpreted as providing a defense to any violation of the CAA by sources that, for example, fail to obtain PSD permits or comply with NSPS before construction.

and lowest emitting design for a fossil-fuel fired power plant, and because a proposed new source may choose to construct as an NGCC facility. However, proposed coal-fired power plants that have already received a PSD permit and that have incurred substantial sunk costs and developed plans to commence construction in the very near future are not in the same position as non-transitional sources. Applying the 1,000 lb CO_2/MWh standard would likely result in the loss of their sunk costs and would likely cause multi-year delays, or even abandonment, of their plans to construct. (Nor is the 1,000 lb CO_2/MWh standard appropriate for CCS sources, as discussed below.) This is not within the scope of BSER.

However, we do not have sufficient information concerning the 15 proposed sources to identify which ones may be in this position. Specifically, we do not have information as to the extent of their sunk costs, their preconstruction planning, or their overall business plans.

Accordingly, we propose to include a requirement that proposed sources must commence construction within 12 months of today's rulemaking proposal as a mechanism for revealing which of these sources qualifies as a transitional source. We believe that any of these 15 proposed sources that commences construction within 12 months of today's rulemaking proposal should be considered to have incurred substantial sunk costs and will have engaged in sufficient preconstruction planning so that the 1,000 lb CO_2/MWh standard should not apply. Any of these 15 proposed sources that do not commence construction within this period should not be considered to be similarly situated. For any of these latter sources that ultimately are constructed, the 1,000 lb CO_2/MWh standard would apply.

Having identified which proposed sources could qualify as transitional sources, we further believe that for several reasons, it is not appropriate to propose any standard of performance for those sources. As noted above, we necessarily lack information specifically as to which of the 15 proposed sources will actually qualify as transitional sources, and, given the range of size, fuel types, and technologies among these proposed sources, that renders it problematic to propose standards of performance. In addition, for the proposed sources that are planning to install CCS, we lack important information concerning the extent to which they are planning to capture CO_2 or their costs to do so. We also lack information as to whether they have made contractual arrangements for the sale of the CO_2 or carbon credits, which may be critical to their financing arrangements. In addition, attempting to propose a standard of performance would give rise to serious practical problems that would undermine the usefulness of the requirement that sources commence construction within 12 months of today's rulemaking proposal as a mechanism for revealing which of these sources qualifies as a transitional source. These include creating uncertainty as to the level of the final standard of performance to which the proposed sources would be subject, which may have the effect of forcing them to delay commencing construction until after we finalize the standards, at which time they would have missed their 12-month window to commence construction and as a result, would fail to qualify as transitional sources. We note that CAA section 111 does not require that we propose or promulgate standards of performance for all sources in a source category, and on numerous occasions in past rulemakings the EPA has taken the similar approach of not proposing standards of performance for all sources in the source category.

Even without an applicable standard of performance, transitional sources will remain constrained in their emissions of CO_2 by the requirements of their PSD permits. In addition, although transitional sources would not be subject to the 1,000 lb CO_2/MWh standard for new sources, the EPA anticipates that transitional sources would become subject to the requirements the EPA would promulgate at the appropriate time, for existing sources under 111(d).

2. Identification of Transitional Sources

For purposes of this action, we define a transitional source as a coal-fired power plant that has received approval for its complete PSD preconstruction permit by the date of this proposal (or that has an approved PSD permit that expired and for which the source is seeking an extension, if the source has been issued or awarded a DOE CCS loan guarantee or grant) for the project, and that commences construction within 12 months of the date of this proposal. For this purpose, the date of this proposal is the date of publication in the **Federal Register** of this notice of proposed rulemaking. The 12-month period would not be extended for any reason, including because of any challenges to the permit that may be brought in any Federal or State court or agency.

The EPA is aware of approximately 15 sources that could potentially qualify as transitional sources because, except as otherwise noted, they have obtained PSD permits but have not yet commenced construction. These proposed sources vary considerably one from another. They range in size from as small as 80 megawatts (MW) to as large as 1320 MWs; they will burn different fuels: conventional coal, waste coal, or petcoke; and they will use different technologies: Circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), supercritical pulverized coal, or sub-critical pulverized coal.

Based on recent industry practice, it appears that no more than a few of these sources will be constructed.[66]

Of these 15 identified potential transitional sources, six have indicated that they plan to install CCS (and in most if not all cases have been issued or awarded a DOE CCS loan guarantee or grant). These six projects are: The Texas Clean Energy Project in Texas, the Trailblazer project in Texas, the Taylorville project in Illinois, the Good Spring facility in Pennsylvania, the Power County Advanced Energy Center in Idaho and the Cash Creek Generation Plant in Kentucky. The remaining nine plants, which are without CCS, are: Limestone 3, White Stallion and Coletto Creek in Texas, Holcomb 2 in Kansas, James De Young and Wolverine in Michigan, Washington County in Georgia, Bonanza in Utah, and Two Elk in Wyoming.[67]

We request that during the public comment period on this rulemaking, each of these EGUs confirm to us that we have correctly identified the status of their PSD permits and, in the case of any sources that had approved permits that are in the process of being extended, and that plan to install CCS, that they have been issued or awarded a DOE CCS loan guarantee or grant. We also request that the sources indicate whether their permits are undergoing challenges before Federal or state authorities or courts. We further request that any other EGU not listed above that has a complete PSD permit and that otherwise meets the parameters for transitional sources described in this

[66] Since 2008, some 15 proposed coal-fired power plants with approved PSD permits have cancelled plans to construct, and since 2009, only one coal-fired power plant has constructed (Southern Company's Kemper County Project, which installed CCS and received DOE funding).

[67] We note that there may be some proposed natural gas-fired EGUs that are similarly situated to the coal-fired transitional sources because the natural-gas fired sources have received PSD permits but have not commenced construction by the date of this proposal. Because they are new gas-fired EGUs, we expect that they will be able to meet the requirements of the proposed new source standard of performance.

section identify itself to us (including indicating whether its PSD permit is undergoing challenge before Federal or state authorities or courts). In our final rulemaking, we intend to include a confirmed list of sources that would qualify as transitional sources if they commence construction within the 12-month period following publication of this proposal in the **Federal Register.**

As commenters have noted, among these 15 proposed sources, some may have incurred substantial sunk costs associated with processing their permits as well as taking additional preconstruction steps (e.g., purchasing land) so that they may be able to commence construction within the near term. As examples of these types of steps, several sources, such as the Texas Clean Energy Project, have signed contracts for the sale of electricity, the sale or disposal of CO_2 or other enabling products, or supporting systems.[68] Although the Taylorville project's PSD permit has expired, the source is seeking to extend it, and the source has entered into CCS funding arrangements with DOE. These actions indicate that this proposed source, too, has sunk costs and may be in a position to commence construction within the near term, and therefore is similarly situated to the other 14 proposed plants (assuming that it is able to secure an extension of its PSD permit).

Even so, we face major gaps in our information about these sources that would inform us at this point as to which of these sources have incurred costs and material commitments to the extent that a 1,000 lb CO_2/MWh standard would be so costly and disruptive as not to be BSER. For example, we do not have specific information as to those sources' specific sunk costs, specific project development actions to date, or overall business plan. Accordingly, we are not able to determine which ones are in a position to commence construction in the near term. In addition, for the sources whose PSD permit indicates that they will install CCS, we do not have specific information as to the amount of CO_2 that they plan to capture; their costs to operate CCS; or their possible revenue streams associated with CCS, such as from the sale or use of CO_2 in enhanced oil recovery or the possible sale of carbon credits in voluntary or other carbon markets.

Instead, the 12-month period, serving as a surrogate for the missing information, provides a mechanism for revealing the qualification of proposed sources for treatment as transitional sources. In light of the complex of requirements, which range from siting to financing, needed to commence construction of a project as large and expensive as a power plant, any proposed source that does commence construction within the relatively short period of 12 months of the date of proposal can be said to have incurred substantial sunk costs and to have taken preconstruction steps by the time of this proposal. It is these sources that would be most disadvantaged by being subjected to the standards of performance proposed in today's rulemaking. The one-year period serves as a type of surrogate for more precise information as to the amount of sunk costs sources must incur or steps leading to commencement of construction that sources must undertake in order to qualify as transitional sources, as well as which sources have incurred those costs or taken those steps, which information is not available at this time. In addition, 12 months is long enough to give these sources a reasonable period to commence construction in accordance with the terms of their permit. Any proposed source that does not commence construction within 12 months cannot be said to be similarly situated.

3. The EPA's Treatment of Transitional Sources

In this action, the EPA is treating transitional sources as a distinct set of sources. We make clear that the proposed standard of performance for non-transitional sources of 1,000 lb CO_2/MWh is not applicable to transitional sources because that standard is not based on the BSER adequately demonstrated for transitional sources. In addition, in light of the unique circumstances of transitional sources, including a lack of information and other considerations, we do not propose any other standard of performance for transitional sources.[69]

Although a transitional source would not be subject to new source CO_2 emissions controls under CAA section 111(b), it would be subject to CO_2 emissions limits due to any CO_2 limits in the source's PSD permit. If the source received the permit prior to January 2, 2011, the permit will not include CO_2 limits, but in that case, as a practical matter, CO_2 emissions would be limited by whatever design or operating constraints are imposed on the source under the PSD permit.

We also note that the fact that transitional sources would not be subject to the proposed standard of performance, would not relieve them from any requirements applicable to existing sources under section 111(d) and related state plans.

4. Legal Basis for the EPA's Treatment of Transitional Sources

In this section, we describe the legal basis for our treatment of transitional sources. First, we identify the relevant CAA section 111 provisions. Second, we explain why the standard of performance we propose for non-transitional sources does not apply to transitional sources, which is because that standard does not reflect the best system of emission reduction adequately demonstrated for transitional sources. Third, we explain why we are not proposing any other standard of performance for transitional sources, which is due to lack of information and other considerations. In the course of these explanations, we discuss the relevant CAA section 111 requirements and our interpretations of them.

a. Key CAA Section 111 Provisions

As the first step in the process of promulgating regulations under section 111, under CAA section 111(b)(1)(A), the Administrator must ''publish * * * a list of categories of stationary sources.'' Then, the Administrator must ''[propose] * * * Federal standards of performance for new sources within [the source] category,'' and then ''promulgate * * * such standards with such modifications as he deems appropriate.'' Section 111(b)(1)(B). Section 111(b)(2) goes on to provide that ''[t]he Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.''

Section 111 includes several key definitions. The provision defines a ''new source'' as ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.'' CAA section 111(a)(2).[70] A

[68] *http://www.texascleanenergyproject.com/newsroom/.*

[69] EPA intends that its treatment of transitional and non-transitional sources be severable from each other and considers that severability is logical because of the record-based differences between the two types of sources and because there is no interdependency in EPA's treatment of the two types of sources. This statement concerning severability for these components in this rulemaking should not be construed to have implications for whether other components in this rulemaking are severable.

[70] The CAA does not include a definition of the term ''commenced'' for these purposes, but the EPA

Continued

''standard of performance'' is defined as a—

standard for emissions of air pollutants which reflects 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.

CAA section 111(a)(2).

Once the Administrator promulgates standards for new sources under CAA section 111(b), the States, consistent with EPA regulatory requirements, must take action under CAA section 111(d) to establish requirements for ''any existing source for any air pollutant (i) [that falls into specified categories] but (ii) to which a standard of performance under this section would apply if such existing source were a new source. * * *'' Section 111(d)(1). An ''existing source'' is defined as ''any stationary source other than a new source.'' Section 111(a)(6).

b. Reasons for Not Applying the 1,000 lb CO_2/MWh Standard of Performance to Transitional Sources

(i) Introduction

In this action, the EPA is treating transitional sources as a distinct set of sources, although the EPA is not establishing a specific subcategory for these sources in the regulatory provisions.[71] Under CAA section 111, the EPA may not apply a standard of performance to sources unless it reflects the ''best system of emission reduction'' (BSER) adequately demonstrated.

As noted, the EPA proposes that non-transitional source fossil-fired power plants that commence construction after the date of proposal are subject to the standard of 1,000 lb CO_2/MWh, and the EPA proposes to base this standard on the EPA's identification of natural gas combined cycle (NGCC) as the BSER adequately demonstrated. The EPA justifies this proposal because owners or operators contemplating construction of non-transitional power plants to serve baseload and intermediate load demand have choices: They can choose the type of facility and therefore may choose to construct a NGCC plant. As a result, for these sources, NGCC constitutes the BSER, and the 1,000 lb CO_2/MWh emission limit reflects that BSER and therefore is the appropriate standard of performance under section 111. Moreover, for those that choose to construct a coal-fired unit, they may choose to construct the plant in a place and a manner that allows installation of CCS—and thereby meet the 1,000 lb CO_2/MWh standard—either at the time of construction or, in accordance with the 30-year averaging proposal, some years later.

(ii) Transitional Sources and NGCC

In contrast, the circumstances surrounding transitional sources are quite different. Transitional sources are a very small group of sources with a distinct profile of costs, preconstruction planning, overall business plans, technical and design concerns, and equitable concerns. Because they are such large facilities, their sunk costs and planning horizons are substantial.

Transitional sources have already incurred substantial costs in permitting and taking other steps preparatory to commencing construction as coal-fired power plants within 12 months of the date of this proposal, which may include purchasing land for the new facility. Considering these sunk costs, converting their plant design to NGCC would be significantly more expensive than for proposed non-transitional sources that have not reached the stage of development that transitional sources have reached. The EPA is required to consider costs in determining the BSER adequately demonstrated, and under these circumstances, the costs factor points away from treating NGCC as BSER for transitional sources.

In addition, because transitional sources have obtained a PSD permit and have developed their plans to the point where they are on the verge of commencing construction, the converting of their plant design to NGCC would be significantly more disruptive to their plans than for proposed non-transitional sources. It may require them to start over the process of developing the plant, and thereby render futile the planning and steps they have taken to date. These losses would, at a minimum, lead to delays in their commencing construction that realistically would be measured in years, and in fact may lead them to abandon the project.

Although the potentially significant planning impacts at issue here are not explicitly identified as part of the definition of the ''standard of performance,'' they should nevertheless be considered in determining the BSER. This is because CAA section 111(a)(2), in its definition of ''new source,'' clearly contemplates that sources are expected to be able to commence construction after the EPA proposes, and before the EPA promulgates, a standard of performance applicable to them. There is nothing in CAA section 111 that suggests that Congress expected that the EPA may determine the BSER in a way that would significantly disrupt the plans of the regulated sources that are implicated here. Therefore, for this reason, too, the 1,000 lb CO_2/MWh standard cannot be considered to reflect the BSER for transitional sources, and therefore cannot be the appropriate standard of performance.

Nor can transitional sources reasonably be expected to meet the 1,000 lb CO_2/MWh standard through the installation of CCS, for the reasons discussed below.

Note that the EPA takes the position that in this particular action, both of those factors—sunk costs and extent of planning to commence construction—must be considered in determining whether the 1,000 lb CO_2/MWh standard reflects the BSER adequately demonstrated. That is, both are necessary conditions, and neither one, by itself, is a sufficient condition. We believe that these reasons concerning costs and planning suffice to justify our position that the 1,000 lb CO_2/MWh standard is not appropriate for transitional sources.

(iii) Coal-Fired Transitional Sources Not Designed for CCS

As noted, while it is generally the case that proposed new sources could choose to build coal-fired power plants with CCS and thereby meet the 1,000 lb CO_2/MWh standard, that is not the case for those transitional sources that are not designed for CCS. As a practical matter, it would be challenging for such a source to proceed with construction without substantial re-design of the project in order to install CCS and thereby be in compliance with the 1,000 lb CO_2/MwH standard. There are several reasons for this. First, captured CO_2 must be sequestered or used. If this was not considered as part of the original site selection, the source will likely be significantly challenged in its efforts to adopt CCS. Second, if CCS was not considered in the original project

framework regulations promulgated under section 111 define this term as follows:

Commenced means, with respect to the definition of new source in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

40 CFR 60.2.

[71] Section 111(b)(2) authorizes the EPA to ''distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.'' In other words, once the EPA selects the set of sources for which to propose regulations, the EPA may establish subcategories among those new sources and promulgate different standards for those subcategories.

design, space considerations may make it difficult to now accommodate it in the facility's design. Third, the requirement to use CCS could necessitate a change in the very power generation technology that a source may choose to use. For instance, instead of building a pulverized coal boiler, IGCC technology may be more appropriate. This is not to say that CCS could not be added to a project at this stage. Projects like the AEP Mountaineer project have shown that CCS can be successfully retrofitted into an existing plant. However, unlike in an existing facility where retrofit decisions must take into account previously made design decisions, in a facility in the pre-design phase, there is more opportunity for cost savings from re-designing the project, rather than having to adapt through retrofit.

It bears emphasis that the requirements created by the new source standard in today's action are fundamentally different from post-combustion controls required to meet new source standards for conventional pollutants in the sense that those controls could be much more easily re-designed into an already planned plant without changing the plant's basic underlying characteristics (such as type of unit or even location). In contrast, CCS is more fundamental to both the design and siting of a unit, and therefore would likely involve fundamental changes to the underlying project. This is much more difficult in a project that has progressed through the permitting stage and is very close to commencing construction than it would be in other types of projects.

(iv) Coal-Fired Transitional Sources Designed for CCS

Although some of the proposed sources that may qualify as transitional sources are planning for CCS, that does not provide a basis for concluding that the 1,000 lb CO_2/MWh standard is appropriate for them. As noted, the EPA is not, in this rulemaking, proposing that CCS is the BSER adequately demonstrated for coal-fired EGUs.

Moreover, these proposed sources have established their location and developed their business plans without the expectation that the proposal in this rulemaking for CCS would apply to them. For example, their plans may assume installing CCS in a manner that results in emissions at levels higher than 1,000 lb CO_2/MWh, or it may assume the sale of emission reduction credits based on an allowable emission rate above 1,000 lb CO_2/MWh. Imposition of an unexpected emission rate requirement at such a late date could upset carefully crafted financial plans, causing delay or even cancellation of the project.

Importantly, we do not have information as to key components of their proposed project and business plan, including, among other things, the amount of capture from the planned CCS system or possible revenue streams associated with CCS. Any proposal for what is BSER would depend on those costs and other information. Accordingly, we are not able to propose determinations that are essential to proposing the BSER for these proposed sources. As a result, we are not able to propose a standard of performance for these proposed sources.

(v) Equitable Considerations

For all transitional sources, the costs and delays discussed above give rise to equitable considerations that also support our treatment of these proposed sources. As noted, owners or operators of transitional sources have incurred significant expenses and undertaken a long planning period that has led them to being able to commence construction in the very near future, and, having invested so substantially in their current plans, should as an equitable matter be allowed to proceed without concern about requirements other than those in their PSD permits. To reiterate, they are in a posture that is fundamentally different from non-transitional sources.

c. Reasons for Not Applying Other Standard of Performance

Although, for the reasons described above, the 1,000 lb CO_2/MWh standard that the EPA proposes for non-transitional sources does not reflect BSER for transitional sources, the EPA is not proposing any other standard of performance for transitional sources. It is reasonable to read section 111 not to require the EPA to propose a standard of performance when faced with the specific circumstances presented by transitional sources in the context of this rulemaking. These circumstances include: (1) The EPA's lack of information with regard to these sources and the appropriate BSER for these sources; (2) the unique challenges with regard to adaptation of proposed projects to the requirements of this standard; (3) the small number of these sources and the possibility that promulgating a standard of performance would not have a beneficial environmental impact; and (4) although transitional sources would not be subject to the 1,000 lb CO_2/MWh standard for new sources, the EPA anticipates that transitional sources would become subject to the requirements the EPA would promulgate at the appropriate time, for existing sources under 111(d).

(i) CAA Requirements for Promulgating Standards of Performance for Sources in a Source Category

The EPA interprets the CAA provisions described above to authorize the EPA not to promulgate a standard of performance for transitional sources. Under section 111(b)(1)(B), once the EPA lists a category of sources, the EPA is required to propose and promulgate standards of performance for new sources in that category. The EPA is not, however, required to promulgate standards of performance that cover all new sources . This is clear from the directive in section 111(b)(1)(B), which requires that the EPA propose standards of performance ''for new sources'' within the category, but does not require that the EPA propose such standards for *all* new sources or for *any* new source. The EPA may fulfill that directive by proposing standards that cover some, but not all, sources that newly commence construction or modification.

Similarly, the term ''new source'' in section 111(a)(2) is defined to incorporate the limitation that the EPA must propose or promulgate a standard applicable to the source for the source to be considered ''new.'' That is, section 111(a)(2) defines a ''new source'' as any source for which construction or modification commences after the EPA proposes ''a standard of performance * * * which will be applicable to such source.'' By its terms, this provision contemplates that the EPA may not propose a standard of performance applicable to certain sources, and that if the EPA does not, those sources would not be considered to be ''new source[s]'' and therefore not subject to any new source standard of performance.

Thus, these provisions do not, by their terms, mandate that the EPA propose standards for each and every source in the source category. Under *Chevron* step 1, these provisions do not unambiguously require that the EPA propose standards of performance for all sources in the source category. We read these provisions as according the EPA some measure of discretion for the EPA to determine not to set standards for a particular portion of the source category, where appropriate, bounded by the principle of rationality. If these provisions are read to be ambiguous as to whether the EPA has discretion to propose and promulgate standards of performance for all sources in the source category, we believe it reasonable to read the provisions to provide such discretion in appropriate circumstances and that such reading is entitled to

deference under *Chevron* step 2. In addition, interpreting these provisions to give the EPA the discretion not to propose and promulgate standards covering all sources in a category under appropriate circumstances—such as those present here—is consistent with the caselaw that authorizes agencies to establish a regulatory framework in an incremental fashion, that is, a step at a time.[72]

(ii) Precedents in Prior NSPS Rulemakings

In applying section 111 over the past several decades, there have been a number of rulemakings in which the EPA has promulgated new source performance standards that do not cover all sources within the relevant source category that newly commence construction or modification. Some examples include the following: (i) In an early NSPS, involving lime kilns, the EPA promulgated an NSPS for certain types of kilns, but not for all types of sources that remained within the relevant source category. The DC Circuit, in its opinion reviewing the rule, noted this state of affairs, without expressing concerns. *National Lime Ass'n* v. *EPA,* 627 F.2d 416, 426 & n. 28 (DC Cir. 1980) (noting that ''of the various types of kilns that may be used in the calcinations of limestone, only rotary kilns are regulated by the standards,'' and not ''the vertical kiln; the rotary hearth kiln; and the fluidized bed kiln''). (ii) In the EPA's initial promulgation of NSPS regulations for petroleum refineries, the EPA did not promulgate standards of performance for certain units, including fluid coking units, delayed coking units, and process heaters, instead promulgating standards of performance for those units subsequently. *See* 40 CFR 60.100a(a); ''Standards of Performance for Petroleum Refineries: Proposed Rules,'' 72 FR 27178 (May 14, 2007). (iii) Similarly, in the EPA's recent revision of the NSPS regulations for coal preparation and processing plants, the EPA ''expand[ed] applicability of the existing NSPS by revising the definitions of thermal dryers, pneumatic coal-cleaning equipment, and coal. It also establishe[d] work practice standards for open storage piles. The final rule amend[ed] the definition of thermal dryer for units constructed, reconstructed, or modified after May 27, 2009, to include both direct and indirect dryers drying all coal ranks (*i.e.,* bituminous, subbituminous, lignite, and anthracite coals) and coal refuse.'' ''Standards of Performance for Coal Preparation and Processing Plants,'' 74 FR 51950, 51952 (Oct. 8, 2009). (iv) In subpart KKKK of the NSPS regulations, the EPA promulgated regulations for the source category of stationary combustion turbines. The EPA did not promulgate regulations for turbines with smaller than 10 MMBtu/hr heat input, emergency units, or combustion turbine test cells. 40 CFR 60.4305(a), 60.4310(a), (d). (v) For other source categories, the EPA also declined to propose and promulgate standards of performance for the smaller sources. For example, for the source category of metal furniture coating operations, the EPA did not apply standards of performance to metal furniture surface coating operations that use less than 3.842 liters of coating (as applied) per year. 40 CFR 60.310(b). (vi) In proposing standards of performance for natural gas processing plants, the EPA proposed standards for only two of the three emission points in the plants (''storage emission sources'' and ''equipment leaks'') and declined to propose standards for the third emission point (''process emission sources'') on grounds that ''[b]est demonstrated control technology has not been identified for [the latter] sources.'' ''Standards of Performance for New Stationary Sources; Onshore Natural Gas Processing Plants in the Natural Gas Production Industry, Equipment Leaks of VOC,'' 49 *FR* 2636, 2637 (January 20, 1984).

(iii) Lack of Basis for Specifying Information

A major reason why the EPA is not proposing a standard of performance for transitional sources is that it is relying, in part, on the one-year commence-construction limit to qualify a source as transitional: The EPA does not have sufficient information about the proposed sources' sunk costs and preconstruction steps to be able to identify which of these proposed sources may qualify as transitional sources. In addition, even if the EPA could determine that a particular proposed source would in fact become a transitional source, the EPA lacks information that, under these circumstances, may be important for determining BSER. For example, the EPA lacks information as to the amount of the proposed source's sunk costs, which may be relevant in determining BSER for these proposed sources. In addition, for proposed CCS sources, as noted above, the EPA does not have information as to key components of their proposed project and business plan, including, among other things, the amount of capture from the planned CCS system or possible revenue streams associated with CCS.

Moreover, because transitional sources are defined by reference to the fact that they will commence construction within 12 months of the date of this proposal, it would be futile for the EPA to attempt to develop that information and then issue a proposal. By the time the EPA could do this, which would likely take at least a year, this set of sources will have become a null set: They either will have commenced construction, such that they would no longer be deemed ''new sources'' for purposes of CAA section 111, or they will not have commenced construction, such that they would be subject to the new source standard for non-transitional sources we are proposing today.[73]

(iv) Practical Problems

In addition, the EPA's lack of information and other considerations give rise to several serious practical problems that would arise were the EPA to propose a standard of performance for transitional sources. Importantly, were the EPA to propose a standard of performance, all transitional sources would face substantial uncertainty as to what final standard the EPA would promulgate. This uncertainty would arise for several reasons. As noted, the EPA lacks information concerning transitional sources. In addition, transitional sources differ one from another in terms of design and in other respects, which would render the EPA's task more complex. As a result, there is risk that the EPA might finalize standards of performance different from what the EPA proposed. The final standards of performance may be more difficult for a given transitional source to meet.

[72] As the U.S. Supreme Court recently stated in *Massachusetts* v. *EPA,* 549 U.S. 497, 524 (2007): ''Agencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop;'' and instead they may permissibly implement such regulatory programs over time, ''refining their preferred approach as circumstances change and as they develop a more nuanced understanding of how best to proceed.'' *See Grand Canyon Air Tour Coalition* v. *F.A.A.,* 154 F.3d 455 (DC Cir. 1998), *City of Las Vegas* v. *Lujan,* 891 F.2d 927, 935 (DC Cir. 1989), *National Association of Broadcasters* v. *FCC,* 740 F.2d 1190, 1209–14 (DC Cir. 1984).

[73] Note that because the basic rationale for EPA's treatment of transitional sources is that they have already incurred substantial sunk costs and have positioned themselves to be close to commencing construction, and the one-year period for commencing construction is a surrogate for that, this treatment of transitional sources cannot logically be stretched to cover sources that do not commence within a substantially longer period. There is no reason to believe those latter sources would have, by the time of the proposal for the rest of the source category, already incurred significant costs and moved close to commencing construction.

Other forms of uncertainty may arise as well. For example, a possible standard of performance that the EPA would consider would be based on identifying the BSER for transitional sources as the controls to which they would be subject under the terms of their PSD permits, with no further controls under section 111.[74] With this approach, the EPA would need to determine the emission rate for each source that would reflect that source's level of CO_2 emissions in accord with the terms of its PSD permit. This emission rate would constitute the ''no-further-control'' standard of performance. Note that under such an approach, each source would receive an emission limit unique to that source. However, some of the transitional sources may have a PSD permit that does not regulate CO_2 because GHGs were not subject to PSD until the January 2, 2011 effective date of the first regulatory action controlling CO_2 emissions under the CAA. Particularly for those sources, this approach could create uncertainty as to what the EPA would promulgate as the emission rate in the final standard of performance. This is because since these sources' permits do not specify a CO_2 limit, the EPA would have to develop limits based on the design of the unit (including the project's type of technology and fuels).

The uncertainties that the sources could experience as to what the final standards of performance would entail could well deter those sources from commencing construction until the EPA promulgated the final standard of performance. Such delay would undermine the usefulness of the requirement that sources commence construction within 12 months of today's rulemaking proposal as a mechanism for revealing which of these sources qualifies as a transitional source, and thus defeat the policy underlying the EPA's approach to transitional sources, which, for the reasons explained above, is to exclude from coverage by this new source standard only those sources that commence construction within 12 months of proposal. If sources are deterred from commencing construction until after the final rule, they will have lost the benefit of the 12-month window. As another practical problem, we also note concern with attempting to promulgate standards of performance for transitional sources at a time when it may reasonably be expected that some of the 15 sources with PSD permits may well not commence construction within 12 months (or may never do so). As a result, the effort to develop a standard of performance for those sources would have been unnecessary.

(v) Small Number of Transitional Sources, Lack of Environmental Benefit

As part of our reasoning for not proposing a standard of performance for transitional sources, we also take into consideration the fact that we expect the number of transitional sources to be small, no more than a few of the 15 potential sources listed above. Further, if we were to propose a ''no further control'' standard of performance, as described above, that approach would provide little, if any, environmental benefit because that standard would not likely provide further control beyond the limits of the sources' PSD permits. In fact, treating transitional sources as existing sources may achieve more reductions than a no-further-control NSPS standard for those sources by including them under the flexible existing source standard that the EPA expects to promulgate.

(vi) Other Considerations

The EPA's approach of not proposing a standard of performance for transitional sources does not leave these sources uncontrolled. Rather, they would remain subject to whatever CO_2 emission limits are included in, or result from compliance with, their PSD permits. And, although transitional sources would not be subject to the 1,000 lb CO_2/MWh for new sources, the EPA anticipates that transitional sources would become subject to the requirements the EPA would promulgate at the appropriate time for existing sources under 111(d).

In notable contrast, in the previous rulemakings cited above in which the EPA did not propose coverage of all sources within the relevant source category, because of the pollutants at issue in these actions, the decision not to propose coverage of all sources within the relevant source category operated without the assurance afforded by section 111(d) that uncovered sources would necessarily be picked up as existing sources subject to existing source guidelines. Where, as here, that assurance mechanism applies, the recognition and application of the Agency's discretion to not propose coverage of all sources in the source category is all the more appropriate.

We recognize that this approach of not proposing a standard of performance for transitional sources could raise the question of consistency with the requirement implicit in the definition of ''new source'' under CAA section 111(a)(2) that a source be subject to a standard of performance when it commences construction after the date of proposal for that standard. We believe the approach is consistent with, and does not circumvent, that requirement. As noted, CAA section 111 does not require that all sources that newly commence construction be treated as new sources, and in past section 111 rulemakings, the EPA has not applied the standards of performance that it proposes and promulgates to all sources that newly commence construction in a source category. In addition to the reasons for not promulgating a standard for transitional sources provided above, where, as here, the pollutants covered by the proposed new source standard give rise to an obligation to develop section 111(d) guidelines for existing sources with the source category, ultimate coverage of the sources in question is inevitable, eliminating any prospect of a regulatory gap of any material concern.

C. Requirements for Reconstructions

1. Overview

The EPA's framework regulations under CAA section 111 provide that reconstructed sources —which, in general, are existing sources that conduct extensive replacement of components—are to be treated as new sources and, therefore, subject to new source standards of performance. In today's rulemaking, we do not propose any standard of performance for reconstructed sources, and we take comment how to approach reconstructions. We note that if we do not establish a new standard of performance for reconstructions, as a practical matter, that would mean that reconstructed sources would be treated as existing sources.

2. Background

a. The EPA Regulations. The EPA's framework regulations, interpreting the definition of ''new source'' in CAA section 111(a)(2),[75] provide that an existing source, ''upon reconstruction,'' becomes subject to the standard of performance for new sources. 40 CFR 60.15(a). The regulations define ''reconstruction'' as—

[T]he replacement of components of an existing facility to such an extent that:

[74] This type of standard of performance could take one of several different forms, such as a standard that would not limit the source's CO_2 emissions, or a standard that the transitional source itself would identify as equaling the emission limit it would achieve through compliance with the applicable terms of its permit.

[75] CAA section 111 does not explicitly include provisions for reconstructed sources.

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

40 CFR 60.15(b). Thus, a reconstruction occurs if the existing source replaces components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility, even if the existing source does not increase emissions. In addition, the component replacement constitutes a reconstruction only if it is technologically and economically feasible for the source to meet the applicable standards.

The regulations go on to require the owner or operator of an existing source that proposes to replace components to an extent that exceeds the 50 percent level, to notify the EPA and to provide specified information, including ''a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.'' In addition, the regulations require the EPA to determine, within a specified time period, whether the proposed replacement constitutes a reconstruction. 40 CFR 60.15(d)–(e).

b. Reconstructions. As with modifications, our base of knowledge concerning reconstructions has depended largely on the enforcement actions brought against power plants and on self-reporting by power plants. Over the lengthy history of the NSPS program, those have been too few in number to allow us to develop a sufficiently robust base of knowledge to propose a standard of performance for reconstructions for GHGs at this time. The EPA is not aware that any power plants are presently planning any project that could meet the requirements for a reconstruction.

2. Options

In this action, the EPA is not issuing a proposal for affected sources that undertake reconstructions. Our reasoning is much the same as with NSPS modifications, which is that the lack of adequate information about the type of source; the type of changes; the extent of emissions increases; and the type of control measures, including their cost and emissions reductions, precludes proposing a standard of performance. Instead of issuing a proposal, the EPA solicits comment on all issues related to reconstructions, including the aspects just noted. Depending on the information the EPA acquires about reconstructions, the EPA may, in the future, propose and promulgate standards of performance for them.

VI. Implications for PSD and Title V Programs

A. Overview

The proposal in this rulemaking would, for the first time, regulate GHGs under CAA section 111. Under the EPA's regulations for the CAA PSD preconstruction permit program, and the CAA Title V operating permit program, regulation of GHGs under CAA section 111 triggers the applicability of PSD. Even so, today's proposal should not require any additional SIP revisions to make clear that the Tailoring Rule thresholds—described below—continue to apply to the PSD program.

This issue arises because States with approved PSD programs in their state implementation plans (SIPs) implement PSD, and most of these States have recently revised their SIPs to incorporate the higher thresholds for PSD applicability to GHGs that the EPA promulgated under what we call the Tailoring Rule.[76] Commenters have queried whether under the EPA's PSD regulations, promulgation of a section 111 standard of performance GHGs would require these states to revise their SIPs again to incorporate the Tailoring Rule thresholds again. The EPA included an interpretation in the Tailoring Rule preamble, which makes clear that the Tailoring Rule thresholds continue to apply if and when the EPA promulgates requirements under CAA section 111. Even so, in today's proposal, the EPA is including a provision in the CAA section 111 regulations that confirms this interpretation.

However, if a state with an approved PSD SIP program that applies to GHGs believes that were the EPA to finalize the rulemaking proposed today, the state would be required to revise its SIP to make clear that the Tailoring Rule thresholds continue to apply, then (i) the EPA encourages the state to do so as soon as possible, and (ii) the EPA will proceed with a separate rulemaking action to narrow its approval of that state's SIP so as to assure that for federal purposes, the Tailoring Rule thresholds will continue to apply as of the effective date of today's rulemaking.

In the alternative, if the Tailoring Rule thresholds did not continue to apply when the EPA promulgates requirements under CAA section 111, then the EPA would shortly proceed with a separate rulemaking action to narrow its approval of all of the State's approved SIP PSD programs to assure that for federal purposes, the Tailoring Rule thresholds will continue to apply as of the effective date of today's proposal.

As discussed below, in the case of title V, today's rulemaking does not have implications for the Tailoring Rule thresholds established with respect to sources subject to title V requirements.

B. Implications for PSD Program

Under the PSD program in part C of title I of the CAA, in areas that are classified as attainment or unclassifiable for NAAQS pollutants, a new or modified source that emits any air pollutant subject to regulation at or above specified thresholds, is required to obtain a preconstruction permit. This permit assures that the source meets specified requirements, including application of best available control technology. States authorized for the PSD program may issue PSD permits. If a state is not authorized, then the EPA issues the PSD permits.

Regulation of GHG emissions in the Light Duty Vehicle Rule (75 FR 25324) triggered applicability of stationary sources to regulations for GHGs under the PSD and title V provisions of the CAA. Hence, on June 3, 2010 (75 FR 31514), the EPA issued the ''Tailoring Rule,'' which establishes thresholds for GHG emissions in order to define and limit when new and modified industrial facilities must have permits under the PSD and title V programs. The rule addresses emissions of six GHGs: CO_2, CH_4, N_2O, HFCs, PFCs and SF_6. On January 2, 2011, large industrial sources, including power plants, became subject to permitting requirements for their GHG emissions if they were already are required to obtain PSD or title V permits due to emissions of other (non-GHG) air pollutants.

Commenters have queried whether, because of the way that the EPA's PSD regulations are written, promulgating the rule we propose today may raise questions as to whether the EPA must revise its PSD regulations—and, by the same token, whether states must revise their SIPs—to assure that the Tailoring Rule thresholds will continue to apply to sources subject to PSD. That is, under the EPA's regulations, PSD applies to a ''major stationary source'' that

[76] ''Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule,'' 75 FR 31514 (June 3, 2010). In the Tailoring Rule, EPA established a process for phasing in PSD and Title V applicability to sources based on the amount of their GHG emissions, instead of immediately applying PSD and title V at the 100 or 250 ton per year or thresholds included under the PSD and title V applicability provisions.

undertakes construction, 40 CFR 51.166(a)(7)(i), and to a ''major modification.'' 40 CFR 51.166(a)(7)(iii). A ''major modification'' is defined as ''any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase * * * and a significant net emissions increase. * * *'' Thus, for present purposes, the key component of these applicability provisions is that PSD applies to a ''major stationary source.'' This term is the regulatory replacement for the term ''major emitting facility,'' which is central to the PSD applicability requirements established in the CAA itself, under sections 165(a)(1) and 169(1).

The EPA's regulations define the term ''major stationary source'' as a ''stationary source of air pollutants which emits, or has the potential to emit, 100 [or, depending on the source category, 250] tons per year or more of any regulated NSR pollutant.'' 40 CFR 51.166(b)(1)(i)(*a*). The EPA's regulations go on to define ''regulated NSR pollutant'' to include, among other things, ''Any pollutant that is subject to any standard promulgated under section 111 of the Act.'' 40 CFR 51.166(b)(49)(ii).

Thus, the PSD regulations contain a separate PSD trigger for pollutants regulated under the NSPS, 40 CFR 51.166(b)(49)(ii) (the ''NSPS trigger provision''), so that as soon as the EPA promulgates the first NSPS for a particular air pollutant, as we are doing in this rulemaking with respect to the GHG air pollutant, then PSD is triggered for that air pollutant.

The Tailoring Rule, on the face of its regulatory provisions, incorporated the revised thresholds it promulgated into only the fourth prong (''[a]ny pollutant that otherwise is subject to regulation under the Act''), and not the second prong (''[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act''). For this reason, a question may arise as to whether the Tailoring Rule thresholds apply to the PSD requirement as triggered by the NSPS that the EPA is promulgating in this rulemaking.

However, although the Tailoring Rule thresholds on their face apply to only the term, ''subject to regulation'' in the definition of ''regulated NSR pollutant,'' the EPA stated in the Tailoring Rule preamble that the thresholds should be interpreted to apply to other terms in the definition of ''major stationary source'' and in the statutory provision, ''major emitting facility.'' Specifically, the EPA stated:

3. Other Mechanisms

As just described, we selected the ''subject to regulation'' mechanism because it most readily accommodated the needs of States to expeditiously revise—through interpretation or otherwise—their state rules. Even so, it is important to recognize that this mechanism has the same substantive effect as the mechanism we considered in the proposed rule, which was revising numerical thresholds in the definitions of major stationary source and major modification. Most importantly, although we are codifying the ''subject to regulation'' mechanism, that approach is driven by the needs of the states, and our action in this rulemaking should be interpreted to rely on any of several legal mechanisms to accomplish this result. Thus, our action in this rule should be understood as revising the meaning of several terms in these definitions, including: (1) The numerical thresholds, as we proposed; (2) the term, ''any source,'' which some commenters identified as the most relevant term for purposes of our proposal; (3) the term, ''any air pollutant; or (4) the term, ''subject to regulation.'' The specific choice of which of these constitutes the nominal mechanism does not have a substantive legal effect because each mechanism involves one or another of the components of the terms ''major stationary source''—which embodies the statutory term, ''major emitting facility''—and ''major modification,'' which embodies the statutory term, ''modification,'' and it is those statutory and regulatory terms that we are defining to exclude the indicated GHG-emitting sources. [Footnote]

[**Footnote:** We also think that this approach better clarifies our long standing practice of interpreting open-ended SIP regulations to automatically adjust for changes in the regulatory status of an air pollutant, because it appropriately assures that the Tailoring Rule applies to both the definition of ''major stationary source'' and ''regulated NSR pollutant.'']

75 FR 31582.

Thus, according to the preamble, the definition of ''major stationary source'' itself already incorporates the Tailoring Rule thresholds, and not just through one component (the ''subject to regulation'' prong of the term ''regulated NSR pollutant'') of that definition. For this reason, it is the EPA's position that the Tailoring Rule thresholds continue to apply even when the EPA promulgates the first NSPS for GHGs (which, as noted above, triggers the PSD requirement under the NSPS trigger provision in the definition of ''regulated NSR pollutant'').[77] To clarify and confirm that the Tailoring Rule thresholds apply to the section 111 prong of the definition of regulated NSR pollutant, in this proposed rulemaking, the EPA is proposing to revise the NSPS regulations, although not the PSD regulations, to explicitly make clear that the NSPS trigger provision in the PSD regulations incorporate the Tailoring Rule thresholds.

As a result, the EPA believes that states that incorporated the Tailoring Rule thresholds into their SIPs may take the position that they also incorporated the EPA's interpretation in the preamble that the thresholds apply to the definition ''major stationary source.''

The EPA requests that all States with approved SIP PSD programs that apply to GHGs indicate during the comment period on this rule whether they can interpret their SIPs already to apply the Tailoring Rule thresholds to the NSPS prong or whether they must revise their SIPs. For any State that says it must revise its SIP (or that does not respond), the EPA expects to propose a rule that is comparable to the SIP PSD Narrowing Rule shortly after the close of the comment period, and expects to finalize that rule at the same time that it finalizes this NSPS rule.

C. Implications for Title V Program

Under the title V program, a source that emits any air pollutant subject to regulation at or above specified thresholds (along with certain other sources) is required to obtain an operating permit. This permit includes all of the CAA requirements applicable to the source. These permits are generally issued through EPA-approved State title V programs.

As the EPA explained in the Tailoring Rule preamble, title V applies to a ''major source,'' CAA section 502(a), which is defined to include, among other things, certain sources, including any ''major stationary source,'' CAA section 501(2)(B), which, in turn, is defined to include a stationary source of ''any air pollutant'' at or above 100 tpy. CAA section 302(j). The EPA's regulations under title V define the term ''major source,'' and in the Tailoring Rule, the EPA revised that definition to make clear that the term is limited to stationary sources that emit any air pollutant ''subject to regulation.'' The EPA incorporated the Tailoring Rule threshold within this definition of ''subject to regulation.'' The EPA

[77] This position reads the regulations to be consistent with the CAA PSD provisions themselves. Under those provisions, PSD applies to any ''major emitting facility,'' which is defined to mean stationary sources that emit or have the potential to emit ''any air pollutant'' at either 100 or 250 tons per year, depending on the source category. CAA section 165(a), 169(1). EPA has long interpreted these provisions to apply PSD to a stationary source that emits the threshold amounts of any air pollutant subject to regulation. See Tailoring Rule, 75 FR 31579. Under these provisions, at present, PSD is already applicable to GHGs because GHGs are already subject to regulation, and regulating GHGs under CAA section 111 does not any additional type of PSD trigger.

described its action as follows in the preamble to the Tailoring Rule:

> Thus, EPA is adding the phrase ''subject to regulation'' to the definition of ''major source'' under 40 CFR 70.2 and 71.2. EPA is also adding to these regulations a definition of ''subject to regulation.'' Under the part 70 and part 71 regulatory changes adopted, the term ''subject to regulation,'' for purposes of the definition of ''major source,'' has two components. The first component codifies the general approach EPA recently articulated in the ''Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by Clean Air Act Permitting.'' 75 FR 17704. Under this first component, a pollutant ''subject to regulation'' is defined to mean a pollutant subject to either a provision in the CAA or regulation adopted by EPA under the CAA that requires actual control of emissions of that pollutant and that has taken effect under the CAA. *See id.* at 17022–23; Wegman Memorandum at 4–5. To address tailoring for GHGs, EPA includes a second component of the definition of ''subject to regulation,'' specifying that GHGs are not subject to regulation for purposes of defining a major source, unless as of July 1, 2011, the emissions of GHGs are from a source emitting or having the potential to emit 100,000 tpy of GHGs on a CO_2e basis.

75 FR at 31,583.

Unlike the PSD regulations described above, the title V definition of ''major source'', as revised by the Tailoring Rule, does not on its face distinguish among types of regulatory triggers for title V. Because title V has already been triggered for GHG-emitting sources, the promulgation of CAA section 111 requirements has no further impact on title V requirements for major sources of GHGs. Accordingly, today's rulemaking has no title V implications with respect to the Tailoring Rule threshold. Of course, unless exempted by the Administrator through regulation under CAA section 502(a), sources subject to a NSPS are required to apply for, and operate pursuant to, a title V permit that assures compliance with all applicable CAA requirements for the source, including any GHG-related requirements. We have concluded that this rule will not affect non-major sources and there is no need to consider whether to exempt non-major sources

VII. Impacts of the Proposed Action

A. What are the air impacts?

The EPA believes that electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of this proposal, because of existing and expected market conditions. We do not project any new coal-fired EGUs without CCS to be built in the absence of this proposal. Accordingly, the EPA believes that this proposed rule is not likely to produce changes in emissions of greenhouse gases or other pollutants although it does encourage the current trend towards cleaner generation.

B. What are the energy impacts?

This proposed rule is not anticipated to have a notable effect on the supply, distribution, or use of energy. As previously stated, we believe that electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of the proposal, because of existing and expected market conditions. In addition, we do not project any new coal-fired EGUs without CCS to be built in the absence of this proposal.

C. What are the compliance costs?

The EPA believes this proposed rule will have no notable compliance costs associated with it, because electric power companies would be expected to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of the proposal, due to existing and expected market conditions. The EPA does not project any new coal-fired EGUs without CCS to be built in the absence of the proposal.

D. How will this proposal contribute to climate change protection?

As previously explained, the special characteristics of GHGs make it important to take initial steps to control the largest emissions categories without delay. Unlike most traditional air pollutants, GHGs persist in the atmosphere for time periods ranging from decades to millennia, depending on the gas. Fossil-fueled power plants emit more GHG emissions than any other stationary source category in the United States, and among new GHG emissions sources, the largest individual sources are in this source category.

This proposed rule will limit GHG emissions from new sources in this source category to levels consistent with current projections for new fossil-fuel-fired generating units. The proposed rule will also serve as a necessary predicate for the regulation of existing sources within this source category under CAA section 111(d). In these ways, the proposed rule will contribute to the actions required to slow or reverse the accumulation of GHG concentrations in the atmosphere, which is necessary to protect against projected climate change impacts and risks.

E. What are the economic and employment impacts?

The EPA does not anticipate that this proposed rule will result in notable CO_2 emission changes, energy impacts, monetized benefits, costs, or economic impacts by 2020. Essentially the EPA believes that owners of newly built electric generating units will choose technologies that meet these standards even in the absence of this proposal due to existing economic conditions as normal business practice. Likewise, we believe this rule will not have any impacts on the price of electricity, employment or labor markets, or the US economy.

F. What are the benefits of the proposed standards?

As previously stated, the EPA does not anticipate that the power industry will incur compliance costs as a result of this proposal and we do not anticipate any notable CO_2 emission changes resulting from the rule. Therefore, there are no direct monetized climate benefits in terms of CO_2 emission reductions associated with this rulemaking. However, by clarifying that in the future, new coal-fired power plants will be required to install CCS, this rulemaking eliminates uncertainty about the status of coal and may well enhance the prospects for new coal-fired generation and the deployment of CCS, and thereby promote energy diversity.

VIII. Request for Comments

We request comments on all aspects of the proposed rulemaking including the RIA. All significant comments received will be considered in the development and selection of the final rule. We specifically solicit comments on additional issues under consideration as described below.

CEMS. We are considering and requesting comment on requiring the use of CO_2 CEMS including stack gas flow rate monitoring for all new affected facilities, including those burning exclusively natural gas and/or distillate oil. In addition, we are requesting comment on requiring the use the following measurement procedures in conducting CEMS relative accuracy testing:

a. EPA Method 2F of 40 CFR part 60 for flow rate measurement during the relative accuracy test audit and performance testing. Method 2F provides velocity data for three dimensions and provides measurements more representative of actual gas flow rates than EPA Method 2 or 2G of 40 CFR part 60.

b. EPA Method 2H of 40 CFR part 60 or Conditional Test Method (CTM)–041

(see: *http://www.epa.gov/airmarkets/emissions/docs/square-ducts-wall-effects-test-method-ctm-041.pdf*) to account for wall effects on for stack gas flow rate calculations during CEMS relative accuracy determinations and for performance testing.

c. EPA Method 4 of 40 CFR part 60 to determine moisture for flow rate during CEMS relative accuracy determinations and for performance test calculations.

d. EPA Method 3A of 40 CFR part 60 for CO_2 concentration measurement and for molecular weight determination during CEMS relative accuracy determinations or for performance testing. Account for ambient air argon concentration of 0.93 percent [78] and a molecular weight of 39.9 lb/lb-mol in calculating the dry gas molecular weight.

e. Measure the stack diameter at the CEMS measurement site and the reference method sampling site with a laser distance measurement device. Determine the mean average of three separate diameter measurements for circular stack areas or the mean average of three depth and width measurements for rectangular measurement areas. Calculate the effective stack area for all flow rate measurements, both CEMS system and Reference Method, using this measurement data. This would be a one-time measurement that would fix the effective area of the stack emissions point unless a new location is chosen for the CEMS or Reference Method measurement point. All calculations involving pi would use a value of 3.14159.

f. Apply a daily calibration drift criteria not to exceed 0.3 percent CO_2 for CO_2 CEMS.

g. Do not exceed a relative accuracy specification of 2.5 percent for both CO_2 and flow rate measurement CEMS.

We also request comment on whether Method 3B of 40 CFR part 60 (integrated bag sample), in addition to Method 3A, should be allowed for CO_2 concentration measurement and for molecular weight determination during CEMS relative accuracy determinations or for performance testing.

Coal refuse. Due to the multiple environmental benefits of remediating coal refuse piles, we are considering and requesting comment on subcategorizing EGUs that burn over 75 percent coal refuse on an annual basis. As part of the GHG listening sessions, one commenter mentioned the advantages of utilizing coal refuse to create electricity. The commenter stated that if net emissions caused by using mining waste to generate electricity are calculated, then mining waste facility would produce no net GHG emissions in the long term and emissions would be no greater than the short term emissions of a combined cycle gas plant in. The comment states that due to the size of the piles, mining waste pile exposure to atmospheric oxygen and pressure promotes heat-generating reactions, primarily oxidation of the mining waste itself (i.e., the coal refuse piles are slowly burning). This process emits CO_2 and other air pollutants. Remediation would stop current and future CO_2 emissions resulting from the uncontrolled combustion of waste piles.

Coordinates. We realize that geographic latitude and longitude coordinates of each stack in terms of decimal degrees are presently reported to the EPA's Clean Air Markets Division in terms of four decimal points to the right of the decimal point. We are requesting comment on whether we should require owners/operators of affected facilities to submit to the EPA Administrator the geographic latitude and longitude coordinates of each stack to have at least six values to the right of the decimal for each location. By way of example, the coordinates for the monument next to Zachary Taylor's tomb in Louisville, KY are 38.279401 latitude and -85.643751 longitude.

Combined Heat and Power. We are also considering and requesting comment on if exempting all CHP facilities where useful thermal output accounts for at least 20 percent of the total useful output from this proposed rule would recognize the environmental benefit of CHP and result in additional installations that would otherwise no occur. In considering exemption of CHP units, the EPA is particularly interested in the overall impact this would have on the composition of new builds. The definition of affected sources under this rule already exempts CHP sources that primarily generate on-site power. Therefore, as explained earlier, today's proposal does not impact any of the small amount of projected coal-fired CHP in EIA's AEO 2011. CHPs that would be covered by this rule generate and sell large quantities of electricity. While building such units is more energy efficient and results in some GHG reductions, building new coal-fired units to meet a standard of 1,000 lb CO_2/MWh would likely result in greater reductions. If potential developers of new coal-fired generation opted instead to build coal-fired CHP to avoid the CO_2 limitations proposed under today's rule, it could result in greater emissions of CO_2. Furthermore, requiring such units to meet a standard of 1,000 lb CO_2/MWh does not preclude new coal-fired units from being CHP units.

Format of the Proposed Standards. Although we have proposed gross output-based emission standards, the EPA believes that the net power supplied to the end user is a better indicator of environmental performance than gross output from the power producer. Net output is the combination of the gross electrical output of the electric generating unit minus the parasitic power requirements. A parasitic load for an electric generating unit is any of the loads or devices powered by electricity, steam, hot water, or directly by the gross output of the electric generating unit that does not contribute electrical, mechanical, or thermal output. In general, less than 7.5 percent of coal-fired station power output, and about 2.5 percent of a combined cycle station power output, is used internally by parasitic energy demands, but the amount of these parasitic loads vary from source to source. Reasons for using net output include (1) recognizing the efficiency gains of selecting EGU designs and control equipment that require less auxiliary power, (2) selecting fuels that require less emissions control equipment, and (3) recognizing the environmental benefit of higher efficiency motors, pumps, and fans. In addition, use of a gross output-based standard could potentially drive the installation of electrically driven feed pumps instead of steam driven feed pumps, even though from an overall net efficiency basis, it may be more efficient to use steam-driven feed pumps. Further, monitoring net output for new and reconstructed facilities can be designed into the facility at low costs. Thus, we are requesting comment on the use of net output-based emission standards for owners/operators of new facilities.

Stationary Simple Cycle Turbines. As stated in the preamble, the intent of the proposed regulations is to cover stationary combustion turbines use for intermediate and base load electric power generation and to exempt stationary combustion turbines used for peaking operations (i.e., simple cycle turbines). We are considering and requesting comment on not including a definition of simple cycle turbines in the final rule. The potential electric output requirement in the definition of electric generating unit would already exclude facilities with permit restricting limiting operation to less than ⅓ of their potential electric output, approximately 2,900 hours of full load

[78] *http://www.physicalgeography.net/fundamentals/7a.html.*

operation annually. The peaking season is generally considered to be less than 2,500 hours annually, and we are requesting comment on if the capacity factor exemption is sufficient such that specifically exempting simple cycle turbine is unnecessary. We are also requesting comment on whether the exemption would provide a perverse incentive to build less efficient simple cycle combustion turbines in order to avoid applicability with the proposed rule. While few existing simple cycle turbines presently generate greater than ⅓ of their potential electric output for sale, we are requesting comment on whether the exemption for simple cycle turbines would result in the greater use of simple cycle turbines for intermediate load applications when more efficient combined cycle facilities would have otherwise been built. In addition, it is our understanding that combined cycle facilities are sometimes built in stages with the combustion turbine engine installation occurring first and the heat recovery steam generator being installed in later years as electricity demand increases. We are requesting comment on whether the exemption would potentially delay the installation of the heat recovery steam generator portion of new combined cycle facilities. Finally, in the event we use the definition approach in the final rule, we are requesting comment on whether a CHP facility that uses the recovered exhaust heat for purposes other than to generate steam and recuperated combustion turbines should be considered simple or combined cycle combustion turbines.

IX. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order (EO) 12866 (58 FR 51,735, October 4, 1993), this action is a ''significant regulatory action'' because it ''raises novel legal or policy issues arising out of legal mandates''. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units.

The EPA believes this rule will have no notable compliance costs associated with it over a range of likely sensitivity conditions because electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of the proposal, because of existing and expected market conditions. (See the RIA for further discussion of sensitivities.) Because our modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance—which is based on the emission rate of a new NGCC unit—would not add costs. The EPA does not project any new coal-fired EGUs without CCS to be built in the absence of this proposal.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2465.01.

This proposed action would impose minimal new information collection burden on affected sources beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively. Apart from certain reporting costs based on requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there are no new information collection costs, as the information required by this proposed rule is already collected and reported by other regulatory programs. The recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this proposal because of existing and expected market conditions. The EPA does not project any new coal-fired EGUs that commence construction after this proposal to commence operation over the 3-year period covered by this ICR. We estimate that 17 new affected NGCC units would commence operation during that time period. As a result of this proposal, those units would be required to prepare a summary report, which includes reporting of excess emissions and downtime, every 6 months.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 60, subpart TTTT. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction (sudden, infrequent, not reasonable preventable, and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has estimated what the notification, recordkeeping, and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals $3,141, and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small. In fact, we estimate that there will be no such occurrences for any new sources subject to 40 CFR part 60, subpart TTTT over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual information collection burden for this collection consists only of reporting burden as explained above. The reporting burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $15,570 and 396 labor hours. This estimate includes semi-annual summary reports which include reporting of excess emissions and downtime. All burden estimates are in 2010 dollars. Average burden hours per response are estimated to be 16.5 hours. The total number of respondents over the 3-year ICR period is estimated to be 36. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID number EPA–HQ–OAR–2011–0660. Submit any comments related to the ICR to the EPA and OMB. See **ADDRESSES** section at the beginning of this notice for where to submit comments to the EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after April 13, 2012, a comment to OMB is best assured of having its full effect if OMB receives it by May 14, 2012. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. et seq.

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as:

(1) A small business that is defined by the SBA's regulations at 13 CFR 121.201 (for the electric power generation industry, the small business size standard is an ultimate parent entity defined as having a total electric output of 4 million MWh or less in the previous fiscal year. The NAICS codes for the affected industry are in Table 4 below);

(2) A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) A small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

TABLE 4—POTENTIALLY REGULATED CATEGORIES AND ENTITIES [a]

Category	NAICS Code	Examples of potentially regulated entities
Industry	221112	Fossil fuel electric power generating units.
Federal Government	[b] 221112	Fossil fuel electric power generating units owned by the federal government.
State/Local Government	[b] 221112	Fossil fuel electric power generating units owned by municipalities.
Tribal Government	921150	Fossil fuel electric power generating units in Indian Country.

[a] Include NAICS categories for source categories that own and operate electric power generating units (includes boilers and stationary combined cycle combustion turbines).
[b] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

We do not include an analysis of the illustrative impacts on small entities that may result from implementation of this proposed rule because we do not anticipate any compliance costs over a range of likely sensitivity conditions as a result of this proposal. Thus the cost-to-sales ratios for any affected small entity would be zero costs as compared to annual sales revenue for the entity. The EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this proposal because of existing and expected market conditions. (See the RIA for further discussion of sensitivities.) Because our modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance—which is based on the emission rate of a new NGCC unit—would not add costs. The EPA does not project any new coal-fired EGUs without CCS to be built. Accordingly, there are no anticipated

economic impacts as a result of this proposal.

Nevertheless, the EPA is aware that there is substantial interest in this rule among small entities (municipal and rural electric cooperatives). In light of this interest, the EPA determined to seek early input from representatives of small entities while formulating the provisions of this proposed regulation. Such outreach is also consistent with the President's January 18, 2011 Memorandum on Regulatory Flexibility, Small Business, and Job Creation, which emphasizes the important role small businesses play in the American economy. This process has enabled the EPA to hear directly from these representatives, at a very preliminary stage, about how it should approach the complex question of how to apply Section 111 of the CAA to the regulation of GHGs from these source categories. The EPA's outreach regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action.

The EPA conducted an initial outreach meeting with small entity representatives on April 6, 2011. The purpose of the meeting was to provide an overview of recent EPA proposals impacting the power sector. Specifically, overviews of the Transport Rule, the Mercury and Air Toxics Standards, and the Clean Water Act 316(b) Rule proposals were presented.

The EPA conducted outreach with representatives from 20 various small entities that potentially would be affected by this rule. The representatives included small entity municipalities, cooperatives, and private investors. We distributed outreach materials to the small entity representatives; these materials included background, an overview of affected sources and GHG emissions from the power sector, an overview of CAA section 111, an assessment of CO_2 emissions control technologies, potential impacts on small entities, and a summary of the listening sessions. We met with eight of the small entity representatives, as well as three participants from organizations representing power producers, on June 17, 2011, to discuss the outreach materials, potential requirements of the rule, and regulatory areas where the EPA has discretion and could potentially provide flexibility.

A second outreach meeting was conducted on July 13, 2011. We met with nine of the small entity representatives, as well as three participants from organizations representing power producers. During the second outreach meeting, various small entity representatives and participants from organizations representing power producers presented information regarding issues of concern with respect to development of standards for GHG emissions. Specifically, topics suggested by the small entity representatives and discussed included: boilers with limited opportunities for efficiency improvements due to NSR complications for conventional pollutants; variances per kilowatt-hour and in heat rates over monthly and annual operations; significance of plant age; legal issues; importance of future determination of carbon neutrality of biomass; and differences between municipal government electric utilities and other utilities.

Small entities expressed concern regarding units making modifications being regulated as new sources. As explained above, we are not proposing a standard of performance for modifications. As a result, sources that undertake modifications would be treated as existing sources and thus would not be subject to the requirements proposed in this notice. As also explained above, the EPA is not proposing standards of performance for existing proposed EGUs, which are referred to as transitional sources, that have acquired a complete preconstruction permit by the time of this proposal and that commence construction within 12 months of this proposal. As a result, any transitional sources owned by small entities would not be subject to the standards of performance proposed in today's rule.

We invite comments on all aspects of the proposal and its impacts, including potential adverse impacts, on small entities.

D. Unfunded Mandates Reform Act of 1995

This proposed rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. The EPA believes this proposed rule will have no compliance costs associated with it over a range of likely sensitivity conditions because electric power companies will choose to build new EGUs that comply with the regulatory requirements of this proposal because of existing and expected market conditions. (See the RIA for further discussion of sensitivities.) As previously explained, because our modeling shows that natural gas-fired plants are the facilities of choice, the proposed standard of performance—which is based on the emission rate of a new NGCC unit—would not add costs. The EPA does not project any new coal-fired EGUs without CCS to be built. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

In light of the interest in this rule among governmental entities, the EPA initiated consultations with governmental entities. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on April 12, 2011, in Washington DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the ''Big 10'' organizations appropriate to contact for purpose of consultation with elected officials. The purposes of the consultation were to provide general background on the proposal, answer questions, and solicit input from state/local governments. The EPA's consultation regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action.

During the meeting, officials asked clarifying questions regarding CAA section 111 requirements and efficiency improvements that would reduce CO_2 emissions. In addition, they expressed concern with regard to the potential burden associated with impacts on state and local entities that own/operate affected utility boilers, as well as on state and local entities with regard to implementing the rule. Subsequent to the April 12, 2011 meeting, the EPA received a letter from the National Conference of State Legislatures. In that letter, the National Conference of State Legislatures urged the EPA to ensure that the choice of regulatory options maximizes benefit and minimizes implementation and compliance costs on state and local governments; to pay particular attention to options that would provide states with as much flexibility as possible; and to take into consideration the constraints of the state legislative calendars and ensure that sufficient time is allowed for state

actions necessary to come into compliance.

E. Executive Order 13132, Federalism

This proposed action does not have federalism implications. It would not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. This proposed action would not impose substantial direct compliance costs on state or local governments, nor would it preempt state law. Thus, Executive Order 13132 does not apply to this action. The EPA consulted with state and local officials in the process of developing the proposed rule to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the proposal, answer questions, and solicit input from state/local governments. The UMRA discussion in this preamble includes a description of the consultation. In the spirit of EO 13132, and consistent with EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Subject to the EO 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

The EPA has concluded that this proposed action would not have tribal implications. It would neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. This proposed rule would impose requirements on owners and operators of new EGUs. The EPA is aware of three coal-fired EGUs located in Indian Country but is not aware of any EGUs owned or operated by tribal entities. The EPA notes that this proposal does not affect existing sources such as the three coal-fired EGUs located in Indian Country, but addresses CO_2 emissions for new EGU sources only.

Because the EPA is aware of Tribal interest in this proposed rule, the EPA offered consultation with tribal officials early in the process of developing this proposed regulation to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action.

Consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of NSPS and emission guidelines for EGUs and offered consultation. A consultation/outreach meeting was held on May 23, 2011, with the Forest County Potawatomi Community, the Fond du Lac Band of Lake Superior Chippewa Reservation, and the Leech Lake Band of Ojibwe. Other tribes participated in the call for information gathering purposes. In this meeting, the EPA provided background information on the GHG emission standards to be developed and a summary of issues being explored by the Agency. Tribes suggested that the EPA consider expanding coverage of the GHG standards to include combustion turbines, lowering the 250 MMBtu per hour heat input threshold so as to capture more EGUs, and including credit for use of renewables. The tribes were also interested in the scope of the emissions averaging being considered by the Agency (e.g., over what time period, across what units). In addition, the EPA held a series of listening sessions on this proposed action. Tribes participated in a session on February 17, 2011 with the state agencies, as well as in a separate session with tribes on April 20, 2011.

The EPA will also hold additional meetings with tribal environmental staff to inform them of the content of this proposal as well as provide additional consultation with tribal elected officials where it is appropriate. We specifically solicit additional comment on this proposed rule from tribal officials.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This proposed action is not subject to EO 13045 because it is based solely on technology performance. The proposal is not expected to produce notable changes in emissions of greenhouse gases or other pollutants but does encourage the current trend towards cleaner generation, helping to protect air quality and children's health. The Agency recognizes that children are among the groups most vulnerable to climate change impacts and the public is invited to submit comments or identify peer reviewed studies relevant to this proposal.

H. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not a ''significant energy action'' as defined in EO 13211 (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This proposed action is not anticipated to have notable impacts on emissions, costs or energy supply decisions for the affected electric utility industry.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs the EPA to use Voluntary Census Standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs the EPA to provide Congress, through annual reports to the OMB, with explanations when an agency does not use available and applicable VCS.

This proposed rulemaking involves technical standards. The EPA cites the following standards in this proposed rule: D5287–08 (Standard Practice for Automatic Sampling of Gaseous Fuels), D4057–06 (Standard Practice for Manual Sampling of Petroleum and Petroleum Products), and D4177–95(2010) (Standard Practice for Automatic Sampling of Petroleum and Petroleum Products). The EPA is proposing use of Appendices B, D, F, and G to 40 CFR part 75; these Appendices contain standards that have already been reviewed under the NTTAA.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this action.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S.

The EPA has determined that this proposed rule would not result in disproportionately high and adverse human health or environmental effects on minority or low-income populations, including any minority, low-income population or indigenous populations.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: March 27, 2012.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of the Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

2. Part 60 is amended by adding subpart TTTT to read as follows:

Subpart TTTT Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units

Applicability

Applicability

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from electric utility generating units that commenced construction after April 13, 2012.

§ 60.5509 Am I subject to this subpart?

You are subject to this subpart if you own or operate an electric utility generating unit that commences construction after April 13, 2012 with a base load rating of more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/h)) heat input of fossil fuel except as specified under § 60.5510(b).

§ 60.5510 What is the affected EGU of this subpart?

(a) The affected facility to which this subpart applies is each electric utility generating unit (EGU) except as provided for in paragraph (b) of this section.

(b) An electric utility generating unit that meets the conditions specified in paragraphs (b)(1) through (b)(3) of this section is exempt from this subpart.

(1) A steam electric generating unit that meets the definition of municipal waste combustor unit and is subject to subpart Eb of this part.

(2) A steam electric generating unit that meets the definition of a commercial or industrial solid waste incineration unit and is subject to subpart CCCC of this part.

(3) Transitional sources.

(i) You are not subject to this subpart if you own or operate a transitional source that commences construction within 12 months after April 13, 2012.

(ii) For purposes of paragraph (b)(3)(ii) a ''transitional source'' is defined as an EGU with a base load rating of more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/h)) heat input of fossil fuel, except as provided for in § 60.5510(b)(1) and (2), and that received a complete permit that meets the requirements of the Prevention of Significant Deterioration Program under part C of Title I of the Clean Air Act prior to April 13, 2012 *(or that had an approved PSD permit that has expired and is in the process of being extended, if the source is participating in a Department of Energy CCS funding program).*

Emissions Standards

§ 60.5515 What greenhouse gases are regulated by this subpart?

The greenhouse gas regulated by this subpart is carbon dioxide (CO_2).

§ 60.5520 What CO_2 emissions standards must I meet?

(a) You must not discharge any gases that contain CO_2 from any affected EGU into the atmosphere in excess of 454 kilograms (kg) of CO_2 per gross output in Megawatt-hours (MWh) (454 kg/MWh) (1,000 lb/MWh) on a 12-operating month annual average basis, except as provided for in paragraphs (b) through (d) of this section.

(b) If the affected EGU utilizes coal or petroleum coke for fuel and is designed to allow installation and operation of a carbon capture and storage (CCS) system, you may comply with each standard in paragraphs (b)(1) through (3) as an alternative to complying with paragraph (a) of this section.

(1) For each year until the 11th year of operation, you must not discharge any gases that contain CO_2 from the affected EGU into the atmosphere in excess of 816 kg/MWh (1,800 lb/MWh) gross output on a 12-operating month annual average basis, and

(2) Beginning with the 11th year of operation, the CCS system must be operational and you must not discharge any gases that contain CO_2 from the affected EGU into the atmosphere in excess of 272 kg/MWh (600 lb/MWh) gross output on a 12-operating month annual average basis, and

(3) You must not discharge any gases that contain CO_2 from the affected EGU into the atmosphere in excess of 454 kg/MWh gross output on a 30-year average basis.

(c) Electric utility generating units located in a non-continental area are not subject to the requirements of this subpart.

(d) Simple cycle combustion turbines are not subject to the requirements of this subpart.

General Compliance Requirements

§ 60.5525 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emissions limits in this subpart applicable to your affected EGU. These limits apply at all times.

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitoring equipment, in a manner consistent with safety and good practices for minimizing CO_2 emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, review of reports required by this subpart, and inspection of the facility.

(c) For each affected EGU subject to the CO_2 emissions limits in § 60.5520, you must measure or calculate a 12 month rolling average CO_2 emission rate, calculated per calendar month, in terms of tons/MWh.

(1) If your EGU is subject to the requirements of 40 CFR 75.10(a)(3)(i), you must use the CO_2 CEMS to measure the 12 month rolling average CO_2 emissions rate.

(d) You must conduct an initial compliance determination for your affected EGU according to the requirements in this subpart within 30 days following the first day of the 13th operating month following the date of initial operations. Thereafter, you must demonstrate continuous compliance according to the requirements in this subpart each calendar month determined to be an operating month.

§ 60.5530 Affirmative Defense for Exceedance of Emission Limit During Malfunction.

In response to an action to enforce the standards you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if the respondent fails to meet its burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, the owners or operators of facilities must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner;

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not result from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(2) Repairs were made as expeditiously as practicable when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs;

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(5) All practicable steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health;

(6) All emissions monitoring and control systems were kept in operation if at all practicable, consistent with safety and good air pollution control practices;

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs;

(8) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) The owner or operator of an affected EGU experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as practicable, but no later than two (2) business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45-day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedances.

Monitoring and Compliance Determination Procedures

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection and the quality assurance and quality control elements consistent with the applicable requirements in § 60.13, 40 CFR part 75, and this section.

(b) Follow the applicable quality assurance procedures for CO_2 emissions in appendices B, D, and G to 40 CFR part 75.

(c) If you determine the your affected EGU's CO_2 mass emissions rate by monitoring fuel combusted in the affected EGU and periodic fuel sampling as allowed under § 60.5525(c)(2), you must use the procedures specified in 40 CFR part 75, appendix G.

(1) Determine a site-specific F factor using the ultimate analysis and GCV in equation F–7a of 40 CFR part 75, Appendix F; and

(2) Monitor and determine the affected EGU's daily fuel consumption for each type of fuel combusted in the affected EGU.

(3) Use ASTM D5287–08 (Standard Practice for Automatic Sampling of Gaseous Fuels) to collect a representative gaseous fuel sample.

(4) Use one of the following methods to collect a representative liquid oil fuel sample:

(i) ASTM D4057–06 (Standard Practice for Manual Sampling of Petroleum and Petroleum Products) or

(ii) ASTM D4177–95 (2010) (Standard Practice for Automatic Sampling of Petroleum and Petroleum Products).

(d) You must monitor and record the applicable data needed to determine your affected EGU's gross output for each operating month.

(e) Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

§ 60.5540 How do I demonstrate compliance and determine excess emissions with my CO_2 emissions limit?

(a) If you use a CO_2 CEMS to demonstrate compliance you must use the procedure specified in paragraphs (a)(1) through (5) of this section to determine the 12-operating month rolling average CO_2 emissions rate for your affected EGU.

(1) Calculate hourly CO_2 mass emissions for each hour of the operating month in terms of kilograms CO_2 using CFR 40 part 75 appendix G.

(2) Determine hourly gross output in terms of MWh for each hour of the operating month.

(3) Sum the hourly CO_2 mass emissions for the operating month, and sum the hourly gross output for the operating month.

(4) Divide the total CO_2 mass emissions calculated for the month by the total hourly gross output calculated for the operating month.

(5) Add the quotient to the sum of the quotients of the previous 11 operating months and divide by 12 to determine the 12-operating month rolling average.

(6) If the 12-operating month rolling average value does not exceed the applicable emissions limit in § 60.5520, your affected EGU is determined to be in compliance with the emissions limit. Otherwise, your affected EGU is determined to have excess emissions.

(b) If you use fuel sampling to demonstrate compliance, you must use the procedure specified in paragraphs (b)(1) through (5) of this section to determine the 12-operating month rolling average CO_2 emissions rate for your affected EGU.

(1) Calculate monthly CO_2 mass emissions by multiplying the monthly F factor by the monthly fuel consumption.

(2) Sum the hourly gross output in terms of MWh for the month.

(3) Divide the monthly CO_2 mass emissions by the sum of the hourly gross output for the month.

(4) Add the quotient to the sum of the quotients of the previous 11 operating months to determine the 12-operating month rolling average.

(5) If the 12-operating month rolling average value does not exceed the applicable emissions limit in § 60.5520, your affected EGU is determined to be in compliance with the emissions limit. Otherwise, your affected EGU is determined to have excess emissions.

(c) If you elect to comply with § 60.5520(b), the 30-year average CO_2 emissions rate for your affected EGU is the sum of the monthly CO_2 emissions for each operating month for the 30-year period divided by the sum of the monthly gross output in terms of MWh for the 30-year period. Use the procedure specified in paragraphs (c)(1) through (4) of this section to determine the 12-month annual average CO_2 emissions rate for your affected EGU.

(1) If you do not use a CO_2 CERMS to demonstrate compliance with § 60.5520(b), you must calculate hourly CO_2 mass emissions for each hour of the 12-month annual period in terms of kilograms CO_2 using CFR 40 Part 75 Appendix G. If you use a CO_2 CERMS to demonstrate compliance with § 60.5520(b) you must calculate hourly CO_2 mass emissions for each hour of the 12-month annual period in terms of kilograms CO_2 using the CERMS hourly mass emissions measurements.

(2) Determine hourly gross output in terms of MWh for each hour of the 12-month annual period.

(3) Sum the hourly CO_2 mass emissions for the 12-month annual operating period, and sum the hourly gross output for the 12-month annual operating period.

(4) Divide the total CO_2 mass emissions calculated for the 12-month annual operating period by the total hourly gross output calculated for the 12-month annual operating period.

(5) If the 12-month annual average value does not exceed the applicable emissions limit in § 60.5520, your affected EGU is determined to be in compliance with the emissions limit. Otherwise, your affected EGU is determined to have excess emissions.

Notification, Reports, and Records

§ 60.5550 What notifications must I submit and when?

(a) You must prepare and submit notifications specified in § 60.7(a) and § 60.19, as applicable to your affected EGU.

(b) You must prepare and submit notifications specified in 40 CFR part 75.61, as applicable to your affected EGU.

§ 60.5555 What reports must I submit and when?

(a) You must prepare and submit reports specified in § 60.7(c) through (e) and § 60.19, as applicable to your affected EGU. All reports required under § 60.7 must be submitted by the 30th day following the end of each 6-month period.

(1) The excess emissions and continuous monitoring systems performance reports and-or summary report forms required in § 60.7(c) must be submitted to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX)(*www.epa.gov/cdx*). In CEDRI, the owner or operator shall use the appropriate electronic reporting form for this subpart or provide an alternate electronic file consistent with EPA's form output format.

(b) You must follow the applicable reporting requirements and submit reports as required in subpart G of 40 CFR part 75. You must report CO_2 mass emissions data, and other related data electronically using the Emissions Collection and Monitoring Plan System (ECMPS).

§ 60.5560 What records must I maintain?

(a) You must maintain records of your information used to demonstrate compliance with this subpart as specified in § 60.7 (b) and (f).

(1) Notwithstanding the requirements of this section you do not need to maintain records of the reports that have been submitted to the EPA's WebFIRE database as required in § 60.5555(a)(1).

(b) You must follow the applicable recordkeeping requirements and maintain records as required in subpart F of 40 CFR part 75.

(c) If you determine the CO_2 mass emissions rate by monitoring fuel combusted in an affected EGU and periodic fuel sampling according to the requirements in this rule then you must maintain records of fuel type and quantity combusted in the affected EGU for each operating month the information specified in paragraphs (c)(1) and (2) of this section.

(1) Records of fuel type and quantity combusted in the affected EGU for each operating month.

(2) Records of the calculations performed to determine the site-specific F factor and monthly total CO_2 mass emissions rates.

(d) Records of the applicable data recorded and calculations performed used to determine your affected EGU's gross output for each operating month.

§ 60.5565 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record except those records required to demonstrate compliance with the emissions limits in § 60.5520(b). Records required to demonstrate compliance with the emissions limits in § 60.5520(b) must be kept for at least 40 years following the date of initial startup of the affected EGU.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.10. You can keep the records off site for the remaining years as required by this subpart.

Other Requirements and Information

§ 60.5570 What parts of the General Provisions apply to me?

Table 1 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5575 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the Administrator and are not transferred to the state, local, or tribal agency; however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions of this part).

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Base load rating means the maximum amount of heat input (fuel) that a steam generating unit can combust on a steady state basis, as determined by the physical design and characteristics of the steam generating unit at ISO conditions. For a stationary combustion turbine *base load* means 100 percent of the design heat input capacity of the stationary combustion turbine engine at ISO conditions.

Carbon capture and storage (CCS) means a process that includes capture and compression of CO_2 produced by an electric utility generating unit before release to the atmosphere; transport of the captured CO_2 (usually in pipelines); and storage of that CO_2 in geologic formations, such as deep saline formations, oil and gas reservoirs, and unmineable coal seams.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Combined cycle means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit.

Combined heat and power, also known as ''cogeneration,'' means a steam-generating unit that simultaneously produces both electric (and mechanical) and useful thermal energy from the same primary energy source.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosene, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Electric utility generating unit or *EGU* means any steam electric generating unit or stationary combustion turbine that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected EGU.

Excess emissions means a specified averaging period over which the CO_2 emissions rate are higher than the applicable emissions standard.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at standard conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross output means the gross electrical or mechanical output from the unit plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of

the unit (*i.e.,* steam delivered to an industrial process).

Integrated gasification combined cycle electric utility generating unit means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction or repair. No solid fuel is directly burned in the unit during operation.

ISO conditions means 288 Kelvin (15° C), 60 percent relative humidity and 101.3 kilopascals pressure.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Operating month means a calendar month during which any fuel is combusted in the electric utility generating unit at any time.

Out-of-control period means any period beginning with the quadrant corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the quadrant corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Potential electric output means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a steam generating unit with a 100 MW (340 MMBtu/h) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity).

Simple cycle combustion turbine means a stationary combustion turbine that which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Steam electric generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated device that provides electricity or useful thermal output to either the boiler or to power auxiliary equipment.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical generation or to enhance the performance of the stationary combustion turbine. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at ISO conditions.

TABLE 1 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A GENERAL PROVISIONS TO SUBPART TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Except for the requirements to submit written excess emissions reports under § 60.7(c).
§ 60.8	Performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	Yes.	
§ 60.14	Modification	No.	
§ 60.15	Reconstruction	No.	

TABLE 1 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A GENERAL PROVISIONS TO SUBPART TTTT—Continued

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements.	Yes.	

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The White House

Office of the Press Secretary

For Immediate Release June 25, 2013

Presidential Memorandum -- Power Sector Carbon Pollution Standards

ENVIRONMENTAL PROTECTION AGENCY

SUBJECT: Power Sector Carbon Pollution Standards

With every passing day, the urgency of addressing climate change intensifies. I made clear in my State of the Union address that my Administration is committed to reducing carbon pollution that causes climate change, preparing our communities for the consequences of climate change, and speeding the transition to more sustainable sources of energy.

The Environmental Protection Agency (EPA) has already undertaken such action with regard to carbon pollution from the transportation sector, issuing Clean Air Act standards limiting the greenhouse gas emissions of new cars and light trucks through 2025 and heavy duty trucks through 2018. The EPA standards were promulgated in conjunction with the Department of Transportation, which, at the same time, established fuel efficiency standards for cars and trucks as part of a harmonized national program. Both agencies engaged constructively with auto manufacturers, labor unions, States, and other stakeholders, and the resulting standards have received broad support. These standards will reduce the Nation's carbon pollution and dependence on oil, and also lead to greater innovation, economic growth, and cost savings for American families.

The United States now has the opportunity to address carbon pollution from the power sector, which produces nearly 40 percent of such pollution. As a country, we can continue our progress in reducing power plant pollution, thereby improving public health and protecting the environment, while supplying the reliable, affordable power needed for economic growth and advancing cleaner energy technologies, such as efficient natural gas, nuclear power, renewables such as wind and solar energy, and clean coal technology.

Investments in these technologies will also strengthen our economy, as the clean and efficient production and use of electricity will ensure that it remains reliable and affordable for American businesses and families.

By the authority vested in me as President by the Constitution and the laws of the United States of America, and in order to reduce power plant carbon pollution, building on actions already underway in States and the power sector, I hereby direct the following:

Section 1. Flexible Carbon Pollution Standards for Power Plants. (a) Carbon Pollution Standards for Future Power Plants. On April 13, 2012, the EPA published a Notice of Proposed Rulemaking entitled "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units," 77 Fed. Reg. 22392. In light of the information conveyed in more than two million comments on that proposal and ongoing developments in the industry, you have indicated EPA's intention to issue a new proposal. I therefore direct you to issue a new proposal by no later than September 20, 2013. I further

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direct you to issue a final rule in a timely fashion after considering all public comments, as appropriate.

(b) Carbon Pollution Regulation for Modified, Reconstructed, and Existing Power Plants. To ensure continued progress in reducing harmful carbon pollution, I direct you to use your authority under sections 111(b) and 111(d) of the Clean Air Act to issue standards, regulations, or guidelines, as appropriate, that address carbon pollution from modified, reconstructed, and existing power plants and build on State efforts to move toward a cleaner power sector. In addition, I request that you:

(i) issue proposed carbon pollution standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2014;

(ii) issue final standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2015; and

(iii) include in the guidelines addressing existing power plants a requirement that States submit to EPA the implementation plans required under section 111(d) of the Clean Air Act and its implementing regulations by no later than June 30, 2016.

(c) Development of Standards, Regulations, or Guidelines for Power Plants. In developing standards, regulations, or guidelines pursuant to subsection (b) of this section, and consistent with Executive Orders 12866 of September 30, 1993, as amended, and 13563 of January 18, 2011, you shall ensure, to the greatest extent possible, that you:

(i) launch this effort through direct engagement with States, as they will play a central role in establishing and implementing standards for existing power plants, and, at the same time, with leaders in the power sector, labor leaders, non-governmental organizations, other experts, tribal officials, other stakeholders, and members of the public, on issues informing the design of the program;

(ii) consistent with achieving regulatory objectives and taking into account other relevant environmental regulations and policies that affect the power sector, tailor regulations and guidelines to reduce costs;

(iii) develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities;

(iv) ensure that the standards enable continued reliance on a range of energy sources and technologies;

(v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses; and

(vi) work with the Department of Energy and other Federal and State agencies to promote the reliable and affordable provision of electric power through the continued development and deployment of cleaner technologies and by increasing energy efficiency, including through stronger appliance efficiency standards and other measures.

Sec. 2. General Provisions. (a) This memorandum shall be implemented consistent with applicable law, including international trade obligations, and subject to the availability of appropriations.

(b) Nothing in this memorandum shall be construed to impair or otherwise affect:

(i) the authority granted by law to a department, agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(c) This memorandum is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

(d) You are hereby authorized and directed to publish this memorandum in the *Federal Register*.

BARACK OBAMA

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Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units

Introduction

The purpose of this memorandum (Legal Memorandum) is to supplement the preamble by providing background for the legal issues discussed in the preamble for this proposed rule[1] and further discussion of some, but not all, of those issues. This memorandum is intended to be read in conjunction with, and assumes familiarity with, the preamble.

I. Background

A. Clean Air Act section 111

Clean Air Act (CAA) section 111, which Congress enacted as part of the 1970 CAA Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision requires EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[2] EPA has listed more than 60 stationary source

[1] The proposed rule is the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units."
[2] CAA section 111(b)(1)(A).

categories under this provision.[3] Once EPA lists a source category, EPA must, under CAA section 111(b)(1)(B), establish "standards of performance" for emissions of air pollutants from new sources in the source category.[4] These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the national ambient air quality standards (NAAQS) or regulated under the CAA section 112 requirements for hazardous air pollutants (HAP). In contrast with CAA section 111(b), which provides for direct federal regulation of new sources, section 111(d)'s mechanism for regulating existing sources provides that states will submit plans that establish "standards of performance" for the affected sources and that contain other measures to implement and enforce those standards.

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[3] *See* 40 CFR 60 subparts Cb – OOOO.
[4] CAA section 111(b)(1)(B), 111(a)(1).

The term "standard of performance" is defined under CAA section 111(a)(1) as a "standard for emissions of air pollutants" that "reflects the degree of emission limitation achievable" from the "best system of emission reduction," considering costs and other factors, that "the Administrator determines has been adequately demonstrated." CAA section 302(l) also defines "standard of performance" as "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction."

Under the EPA's implementing regulations for CAA section 111(d)(1), the EPA must determine the best system of emission reduction for the sources, and then apply that best system to determine the required level of emissions or emission reduction, which the regulations refer to as the "emissions guideline."[5] Under section 111(d)(1), the states must then adopt state plans that establish standards of performance and measures that implement and enforce those standards. In the case of an air pollutant that EPA has determined may cause or contribute to endangerment of

[5] 40 CFR 60.22(b)(5).

public health, the states' standards of performance must not be less stringent than the EPA's emission guideline.[6] CAA section 111(d)(1) grants states the authority, in applying a standard of performance to particular sources, to take into account the source's remaining useful life or other factors.

The state must submit its plan to the EPA for approval, and, under CAA section 111(d)(2), the EPA must approve the state plan if it is "satisfactory."[7] If a state does not submit a plan, the EPA must establish a federal plan for that state.[8] Once a state receives the EPA's approval for its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved state implementation plan (SIP) under CAA section 110.

B. Legislative history

The legislative history of the 1970 Clean Air Act Amendments indicates that at that time, Congress grouped air pollutants from existing stationary sources into three categories: (i) air pollutants that affected the National

[6] 40 CFR 60.24(c).
[7] CAA section 111(d)(2)(A).
[8] *Id*.

Ambient Air Quality Standards (NAAQS), which would be regulated under CAA section 110 state implementation plans (SIPs), (ii) hazardous air pollutants (HAPs), which would be regulated under EPA-promulgated national emission standards pursuant to CAA section 112, and (iii) all other air pollutants. The House bill did not address this third group of air pollutants, but the Senate bill did: it termed them "selected air pollution agents" and proposed to require the EPA to promulgate national emission standards pursuant to proposed CAA section 114. The 1970 House-Senate Conference Committee that was formed to resolve differences between the House and Senate versions of the CAA Amendments did not adopt the Senate bill's proposed CAA section 114, but did adopt section 111(d), which covers the same non-NAAQS, non-HAPs air pollutants. Under section 111(d)(1) as included in the 1970 CAA Amendments, the states were required to submit to the EPA state plans that "establish[] emission standards" for their existing sources. Although the legislative history of the 1970 CAA Amendments does not contain statements that directly discuss the specific provisions included in section 111(d), the legislative history of the Senate bill's proposed section 114 is relevant to the meaning of section 111(d), and we refer to parts of that legislative history below.

For new sources, section 111(b)(1)(B) required the EPA to promulgate "standards of performance," and defined that term, under section 111(a)(1), as—

> a standard for emissions of air pollutants which reflects 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) the Administrator determines has been adequately demonstrated.

The legislative history discusses, among other things, the meaning of the term "standard of performance,"[9] which we refer to below.

In the 1977 CAA Amendments, Congress made several changes to section 111, including section 111(d). Congress substituted "standards of performance" for "emission standards," which, as noted above, the states are required to establish in their state plans. In addition, Congress added to section 111(d)(1) the requirement that the EPA's regulations "permit the State in applying a standard of performance to any particular source under a [section 111(d)] plan … to take into consideration, among other factors, the remaining useful life of the existing source to which such standards applies." Congress added to section

[9] *See, e.g.*, Senate Comm. Rep. No. 91-1196 at 16.

111(d)(2) a similar requirement applicable to federal plans. In addition, Congress revised the definition of "standard of performance" in section 111(a)(1) to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard (i) be based on, in lieu of the "best system of emission reduction … adequately demonstrated," the "best technological system of continuous emission reduction … adequately demonstrated;" and (ii) require a percentage reduction in emissions. In addition, in the 1977 CAA Amendments, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider "any nonair quality health and environment impact and energy requirements." Congress also added the definition of "standard of performance" in section 302(l), which defines the term to require a "continuous emission reduction."

In the 1990 CAA Amendments, Congress made further amendments to section 111, including section 111(d). Among other things, Congress again revised the definition of "standard of performance" under CAA section 111(a)(1), this time repealing the requirements that the standard of performance be based on the best technological system and achieve a percentage reduction in emissions, and replacing

those provisions with the terms used in the 1970 CAA Amendments' version of section 111(a)(1) that the standard of performance be based on the "best system of emission reduction … adequately demonstrated." In addition, in section 111(d)(1)(A)(i), Congress revised the description of which air pollutants are subject to section 111(d) but, as discussed below, left the provision ambiguous with respect to its applicability to the air pollutant emitted from the sources at issue in this rulemaking: CO_2 emissions from fossil fuel-fired EGUs . CAA section 111 has not been revised since the 1990 CAA Amendments.

C. Regulatory history and case law

The EPA issued regulations implementing CAA section 111(d) in 1975,[10] and has revised them in the years since.[11] (We refer to the regulations generally as the implementing regulations.) These regulations provide that, in promulgating requirements for sources under CAA section 111(d), the EPA first develops regulations known as "emission guidelines," which establish binding requirements that states must address when they develop their plans.[12]

[10] "State Plans for the Control of Certain Pollutants From Existing Facilities," 40 FR 53,340 (Nov. 17, 1975).
[11] The most recent amendment was in 77 Fed. Reg. 9304 (Feb. 16, 2012).
[12] 40 CFR 60.22. In the 1975 rulemaking, the EPA explained that it used the term "emissions guidelines" – instead of

The implementing regulations also establish timetables for state and EPA action. The default rule is that states must submit state plans within nine months of the EPA's issuance of the guidelines,[13] but the regulations provide the EPA with authority to extend the deadlines for those submissions.[14] The regulations also provide that the EPA must take final action on the state plans within four months of the due date for those plans.[15] In the present rulemaking, the EPA is following the requirements of the implementing regulations, except that the EPA is extending certain timetables, as described in the preamble.[16]

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (i.e., phosphate fertilizer plants (fluorides), sulfuric acid plants (acid mist), primary aluminum plants (fluorides), Kraft pulp plants (total reduced sulfur), and

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emissions limitations – to make clear that guidelines would not be binding requirements applicable to the sources, but instead are "criteria for judging the adequacy of State plans." 40 Fed. Reg. at 53,343.

[13] 40 CFR 60.23(a)(1).

[14] See id.; 40 CFR 60.27(a).

[15] 40 CFR 60.27(b).

[16] The EPA is not re-opening the existing regulations, although it is revising the deadline for action on state plan submittals. The EPA is proposing additional regulatory requirements, which are contained in proposed subpart UUUU.

municipal solid waste landfills (landfill gases)).[17] In addition, the agency has regulated additional pollutants under CAA section 111(d) in conjunction with CAA section 129.[18] The agency has not previously regulated CO_2 or any other greenhouse gas under CAA section 111(d) (although because landfill gases include methane, the agency's regulation of landfill gases reduced emissions of that greenhouse gas).

The D.C. Circuit has never handed down a decision that interpreted, or reviewed EPA's interpretation of, section 111(d). The D.C. Circuit has, however, reviewed rulemakings under CAA section 111 on numerous occasions during the past four decades, handing down decisions dated from 1973 to 2011.[19] These decisions concerned various

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[17] *See* "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 Fed. Reg. 12,022 (Mar. 1, 1977); "Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist," 42 Fed. Reg. 55,796 (Oct. 18, 1977); "Kraft Pulp Mills, Notice of Availability of Final Guideline Document," 44 Fed. Reg. 29,828 (May 22, 1979); "Primary Aluminum Plants; Availability of Final Guideline Document," 45 Fed. Reg. 26,294 (Apr. 17, 1980); "Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule," 61 Fed. Reg. 9905 (Mar. 12, 1996).

[18] *See, e.g.,* "Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule," 76 Fed. Reg. 15,372 (Mar. 21, 2011).

[19] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974); *Essex*

aspects of section 111, primarily the interpretation of the term "standard of performance." Relevant aspects of these cases are discussed below.

D. Summary of section 111 proposals

The EPA is in the process of conducting three rulemakings to regulate CO_2 from fossil fuel-fired electricity generating units (EGUs), including both fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines (affected sources or affected EGUs). The first, published in January, 2014, proposes standards of performance under CAA section 111(b) for affected sources undertaking new construction. The second is the present rulemaking, under CAA section 111(d), which proposes emission guidelines for states to follow in adopting state plans that regulate existing affected EGUs. In the third rulemaking, which we expect to propose concurrently with the present one, the EPA is proposing standards of performance under section 111(b) for affected EGUs that undertake modifications or reconstructions.

Chemical Corp. v. Ruckelshaus, 486 F.2d 427, (D.C. Cir. 1973), *cert. denied, Appalachian Power Co. v. EPA,* 416 U.S. 969 (1974); *Portland Cement Ass'n v. EPA*, 665 F.3d 177 (D.C. Cir. 2011).

II. Summary of legal basis

The following summarizes the main features of the EPA's legal rationale for this proposed rulemaking. All of this rationale is discussed in the appropriate sections of the preamble for this rulemaking. This Legal Memorandum elaborates on some, although not, all of these features.

Today's proposed action is consistent with the requirements of CAA section 111(d) and the implementing regulations. As an initial matter, the EPA reasonably interprets the provisions identifying which air pollutants are covered under CAA section 111(d) to authorize the EPA to regulate CO_2 from fossil fuel-fired EGUs. Specifically, an ambiguity in the provisions of section 111(d)(1)(A)(i), arising from Congress's simultaneous enactment of two separate versions of this provision, has led some stakeholders to argue that the fact that the EPA has regulated hazardous air pollutants from EGUs prevents the EPA from regulating CO_2 emissions from EGUs. As explained below, however, the EPA reads the provision to authorize regulation of CO_2 emissions from EGUs and this interpretation is both reasonable and entitled to deference.

In addition, the EPA recognizes that CAA section 111(d) applies to sources that, if they were new sources, would be covered under a CAA section 111(b) rule. The EPA intends to complete two CAA section 111(b) rulemakings regulating CO_2 from new fossil fuel-fired EGUs and from modified and reconstructed fossil fuel-fired EGUs before it finalizes this rulemaking, and either of those section 111(b) rulemakings will provide the requisite predicate for this rulemaking.

A key step in promulgating requirements under CAA section 111(d) is determining the "best system of emission reduction ... adequately demonstrated" (BSER). In promulgating the implementing regulations, the EPA explicitly stated that it is authorized to determine BSER;[20] accordingly, in this rulemaking, the EPA is determining BSER.

The EPA is proposing two alternative approaches for the "best system of emission reduction ... adequately demonstrated" for fossil fuel-fired EGUs, each of which is based on methods that have employed for reducing emissions of air pollutants, including, in some cases, CO_2, from these sources. The first identifies the combination of the four

[20] The EPA is not re-opening that interpretation in this rulemaking.

building blocks as the BSER. These include operational improvements and equipment upgrades that the coal-fired steam-generating EGUs in the state may undertake to improve their heat rate (building block 1) and increases in, or retention of, zero- or low-emitting generation, as well as measures to reduce demand for generation, all of which, taken together, displace, or avoid the need for, generation from the affected EGUs (building blocks 2, 3, and 4). All of these measures are components of a "system of emission reduction" for the affected EGUs because they either improve the carbon intensity of the affected EGUs in generating electricity or, because of the integrated nature of the electricity grid and the fungibility of electricity and electricity services, they displace or avoid the need for generation from those sources and thereby reduce the emissions from those sources. Moreover, those measures may be undertaken by the affected EGUs themselves and, in the case of building blocks 2, 3, and 4, they may be required by the states.

Further, these measures meet the criteria in CAA section 111(a)(1) and the case law as the "best" system of emission reduction because, among other things, they achieve the appropriate level of reductions; they are of reasonable cost, including when viewed through a nation-

wide lens; they are consistent with trends in the energy sector; and they encourage technological development and expansion that is important to achieving further emission reductions. Moreover, the measures in each of the building blocks are "adequately demonstrated" because they are each well-established in numerous states, many of them have already been relied on to reduce air pollutants, including CO_2, from fossil fuel-fired EGUs and, as noted, they may be undertaken by the affected EGUs or, in general, required by the states.

For the alternative approach for the BSER, the EPA is identifying the "system of emission reduction" as including, in addition to building block 1, the reduction of affected fossil fuel-fired EGUs' mass emissions achievable through reductions in generation of specified amounts from those EGUs. Under this approach, the measures in building blocks 2, 3, and 4 would not be components of the system of emission reduction, but instead would serve as bases for quantifying the reduction in emissions resulting from the reduction in generation at affected EGUs. In light of the available sources of replacement generation through the measures in the building blocks, this approach also meets the criteria for being the "best" system because of, among other things, the emission

reductions it would achieve, its reasonable cost, its promotion of technological development, as well as the fact that under this approach, the reliability of the electricity system would be maintained. The approach of reduced generation is also "adequately demonstrated" because of the ability of affected EGUs to adjust their own generation, the authority of the state to impose requirements, and the fact that other entities that operate in the various types of markets in the states can be expected to respond to the reduction in generation from the fossil-fuel fired EGUs by undertaking the measures in the building blocks or other actions that would assure reliability.

After determining BSER, the EPA is authorized under the implementing regulations, as an integral component to setting emission guidelines, to apply the BSER and determine the resulting emission limitation. The EPA is proposing to apply the BSER to the affected EGUs on a statewide basis. In this rulemaking, the EPA terms the resulting emission limitation the state goal. The EPA is formulating each state goal as an average emissions rate. The state goals form the EPA's emission guidelines.

With the promulgation of the emission guidelines, each state must develop a plan to achieve an emission performance level that corresponds to the state goal. The state plans must establish standards of performance for the affected EGUs and include measures that implement and enforce those standards. Based on requests from states and other stakeholders, the EPA is proposing that states be authorized to submit state plans that do not impose legal responsibility on the affected EGUs for the entirety of the emission performance level, but instead, by adopting what this preamble refers to as a "portfolio approach," impose requirements on other affected entities -- e.g., renewable energy and demand-side energy efficiency measures -- that would reduce CO_2 emissions from the affected EGUs. (In the preamble and the regulatory text for this proposed rulemaking, we refer to the affected EGUs and other entities with obligations under the state plan as "affected entities.") As noted in the preamble for this rulemaking, a possible basis for this approach is that those requirements on affected entities other than affected EGUs may be authorized as standards of performance or implementing measures. In the preamble, the EPA proposes that this is an appropriate flexibility and solicits comment, but also solicits comment on whether state plans must impose all of

the legal responsibility for achieving the required emission performance level on the affected EGUs.

It should be noted that an important aspect of the BSER for affected EGUs is that the EPA is proposing to apply it on a statewide basis. The statewide approach also underlies the required emission performance level, which, as noted, is based on the application of the BSER to a state's affected EGUs, and which the suite of measures in the state plan, including the emission standards for the affected EGUs, must achieve overall. The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance -- and, for the portfolio approach, in imposing requirements on other affected entities -- as long as, again, the required emission performance level is met.

This state-wide approach both harnesses the efficiencies of emission reduction opportunities in the interconnected electricity system and is fully consistent with the principles of federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly. That is, this provision achieves the emission performance requirements through the vehicle of a state plan, and provides each state significant flexibility to take local circumstances and state policy goals into account in

determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements.

This state-wide approach, and the standards of performance for the affected EGUs that the states will establish through the state-plan process, are consistent with the applicable CAA section 111 provisions.

The preamble further notes that even if the state plan imposes all of the obligations to achieve the required emission performance level on the affected EGUs, the state plan could nevertheless include requirements on other affected entities in order to facilitate the reduced utilization of, and CO_2 emissions from, the affected EGUs – and the practical effect for the EGUs would be the same as under the proposed portfolio approach. The preamble solicits comment on other issues concerning state plans, including whether a state may include in its plan a mechanism to achieve a specified portion of the required emission performance level on behalf of the affected EGUs, and thereby limit the obligations of the affected EGUs.

The EPA emphasizes that in developing the state plans, the states have substantial discretion in designing the standards of performance, as long as the plans reduce emissions from the affected sources to achieve the required

emission performance level. Moreover, the states may require sources to implement specific measures that the EPA does not identify as part of the BSER, and may include other approaches such as, for example, emission trading programs. By the same token, states may allow sources, in complying with their applicable standards of performance, to rely on any measures that will reduce their CO_2 emissions, regardless of whether the EPA identifies those measures as part of BSER, as long as, again, the state plan achieves the requisite level of emissions reduction from the affected entities.

In this rulemaking, the EPA proposes reasonable deadlines for state plan submission and the EPA's action. The proposed deadline for the EPA's action on state play submittals varies from that in the implementing regulations, and the EPA is proposing to revise that provision in the regulations accordingly. Under CAA section 111(d)(2), the state plans must be "satisfactory" for the EPA to approve them, and in this rulemaking, the EPA is proposing the criteria that the state plans must meet under that requirement.

III. Authority to regulate CO_2 from EGUs

CAA section 111 authorizes EPA to regulate CO_2 emissions. The Supreme Court has held that greenhouse

gases (including CO_2) are an "air pollutant" under the CAA. *Massachusetts. v. EPA*.[21] Furthermore, the U.S. Supreme Court's holding in *American Electric Power Co. v. Connecticut*, 131 S. Ct. 2527, 2537-38 (2011), that "the Clean Air Act and the EPA actions it authorizes displace any federal common law right to seek abatement of carbon-dioxide emissions from fossil fuel-fired power plants" was premised on the Court's understanding that section 111, including section 111(d), applies to carbon dioxide emissions from those sources.

The fact that EPA has regulated EGU emissions of mercury and other hazardous air pollutants under CAA section 112 does not deprive EPA of the authority to regulate CO_2 emissions from EGUs under CAA section 111(d) under the Agency's established construction of the ambiguous provisions in CAA section 111(d)(1)(A)(i) that identify the air pollutants subject to CAA section 111(d). The ambiguities stem from apparent drafting errors that occurred during enactment of the 1990 CAA Amendments, which revised section 111(d). The confusion arises because two different amendments to section 111(d) were enacted in the 1990 CAA Amendments – one in title I of the bill, the other

[21] 549 U.S. 497 (2007).

in title III of the bill (both amendments were to be codified in section 111(d)). The confusion is exacerbated because the U.S. Code does not accurately reflect what was enacted – it presents only one of the two amendments. However, the enacted law signed by the President (as recorded in the U.S. Statutes at Large), not the U.S. Code, is controlling.

As presented in the U.S. Code, section 111(d)(1)(A) requires states to submit standards of performance for existing sources "for any air pollutant (i) [1] for which air quality criteria have not been issued or which is not included on a list published under [CAA section 108(a)] or [2] *emitted from a source category which is regulated under [section 112]*." (Emphasis added.) This provision has two components that exclude from section 111(d) two types of air pollutants. The first component, which we call the NAAQS Exclusion, excludes NAAQS pollutants. The second component, which we call the Section 112 Exclusion, presents the ambiguities. As presented in the U.S. Code, the Section 112 Exclusion appears by its terms to preclude from section 111(d) any pollutant if it is emitted from a source category that is regulated under section 112. The U.S. Code version of 111(d) can be read to provide that the provision would not cover GHGs because GHGs are emitted

from EGUs and EGUs are a source category regulated under section 112.[22]

The text of section 111(d) as presented in the U.S. Code, however, does not accurately reproduce the Section 112 Exclusion as enacted in the 1990 CAA Amendments. The correct statement of the Section 112 Exclusion – the one that was enacted by Congress and signed by the President, and which therefore is controlling – is found in the U.S. Statutes at Large. This text incorporates two versions of the Section 112 Exclusion, one passed by the U.S. House of Representatives and one passed by the U.S. Senate. The two versions were never reconciled, and both were enacted as part of the 1990 CAA Amendments. The two versions conflict with each other and thus render the Section 112 Exclusion ambiguous. Under these circumstances, the EPA may reasonably construe the Section 112 Exclusion to authorize the regulation of GHGs under section 111(d).

[22] By the same token, GHGs are emitted by many other source categories, such as refineries, that are regulated under section 112. Indeed, the text as presented in the U.S. Code could be read to exclude virtually every pollutant from regulation under Section 111(d), because it would be difficult to identify any pollutant that is not emitted from at least one source category that is regulated under 112. We do not need to address this ridiculous result, however, for the reasons discussed in the text above.

To understand the different amendments by the House and Senate, one must start with section 111(d)(1) as it read before the 1990 CAA Amendments:

> 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 7412(b)(1)(A) of this title,* but (ii) to which a standard of performance under this section would apply if such existing source were a new source. * * *

42 U.S.C.A. 7411(d)(1) (West 1977); Public Law 95–95 (emphasis added). In this version, the Section 112 Exclusion, by its terms, applied to section 112 pollutants, and not to categories of sources that emit those pollutants. It should also be noted that in the 1990 CAA Amendments, Congress amended section 112 to include a statutory list of hazardous air pollutants for EPA to regulate, instead of relying on EPA to develop its own list.

The 1990 Senate bill amended revised section 111(d)(1)(A)(i) by striking the term to ‘‘112(b)(1)(A)’’ and inserting in its place the term ‘‘112(b).’’ Under this amendment, the text would read as follows (with changes shown in strikeout):

> 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 7412(b) ~~(1)(A)~~ of this title, but (ii) to which a standard of performance under this section would apply if such existing source were a new source.

The 1990 House bill amended section 111(d)(1)(A)(i) of the 1977 CAA by striking the phrase ''or 112(b)(1)(A)'', and inserting in its place the phrase ''or emitted from a source category which is regulated under section 112.'' Under this amendment, the text would read as follows (with changes shown in underline and strikeout):

> 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 ~~7412(b)(1)(A)~~ <u>emitted from a source category which is regulated under section 7412</u> of this title, but (ii) to which a standard of performance under this section would apply if such existing source were a new source.

The House-Senate Conference Committee did not reconcile these two conflicting amendments, and both were

included in the 1990 CAA Amendments as reported by the Conference Committee, approved by both the House and the Senate, and signed by the President. As presented in the Statutes at Large, the Section 112 Exclusion is therefore ambiguous.

The EPA discussed these different amendments in the preamble to "Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List," 70 FR 15994, 16029-32 (March 29, 2005). There, the EPA concluded that the Section 112 Exclusion could be read as follows: Where a source category is regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under section 112(b) that may be emitted from that particular source category. The EPA explained that this approach reasonably interprets the Section 112 Exclusion to give some effect to both amendments. The EPA emphasized that it is not reasonable to give full effect to the House language because a literal reading of that language would mean that the EPA could not regulate any air pollutant from a source category regulated under section 112, a result that would be inconsistent with (i) Congress' desire in the

1990 CAA Amendments to require the EPA to regulate more substances, and not to eliminate the EPA's ability to regulate large categories of air pollutants, and (ii) the fact that the EPA has historically regulated non-hazardous air pollutants under section 111(d), even where those air pollutants were emitted from a source category actually regulated under section 112. *See* 70 FR 16031-32. The EPA continues to view this interpretation of the Section 112 exclusion as reasonable, for the reasons just stated.

Applying this interpretation of the Section 112 Exclusion to this rule, we conclude that section 111(d) authorizes the EPA to establish section 111(d) guidelines for GHG emissions from EGUs. Although EGUs are a source category that is regulated under CAA section 112, GHGs are not a HAP regulated under section 112. Therefore, the Section 112 exclusion in section 111(d) does not apply to GHGs, and 111(d) does not preclude the EPA from establishing guidelines covering GHGs from EGUs.

IV. Rational basis, endangerment finding

In response to the January 2014 Proposal for standards of performance for GHGs emissions from newly constructed fossil fuel-fired EGUs,[23] some stakeholders raised concerns

[23] 79 Fed. Reg. 1,430 (Jan. 8, 2014).

that the EPA could not promulgate those standards without first issuing a finding that GHGs from those sources cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare, under CAA section 111(b)(1)(A). In that proposal, the EPA stated that it is rational to regulate GHGs from fossil fuel-fired EGUs because the EPA has previously found that GHG emissions endanger public health and welfare, and because the electric generating industry emits a significant amount of GHGs. The EPA added that CAA section 111 does not require that EPA issue a formal endangerment finding, and that even if section 111 did require such a finding, the EPA's rational basis would qualify as one.[24] The EPA is taking the same position in the section 111(b) rulemaking proposal to establish standards of performance for GHG emissions from modified and reconstructed fossil fuel-fired EGUs.

The EPA will finalize either or both of the January 2014 Proposal and the rulemaking for modified and reconstructed EGUs by the time that it finalizes this proposed rulemaking. In that event, the EPA would not be required to further address the rational basis or

[24] *See* 79 FR at 1,452/3 – 1,456/1.

endangerment finding in this rulemaking. In any event, these questions are properly addressed and resolved in the context of the parallel rulemakings under section 111(b), not in this rulemaking. Thus, the EPA is not seeking comment in the preamble to this proposal on any issues related to a rational basis or endangerment finding.

V. Authority for EPA to determine BSER and emission guidelines

In this section we describe the authority, as set out in the EPA's implementing regulations under CAA section 111(d), for the EPA to determine the "best system of emission reduction … adequately demonstrated" and the amount of required emission reduction that is based on the BSER. We also describe how, in this rulemaking, the EPA proposes to apply the BSER to each state, and on that basis, to determine the amount of emission limitation achievable by each state, which we refer to as the state goal. The state goal is the "emissions guideline" that the implementing regulations require the EPA to promulgate.

CAA section 111(d) directs the EPA to –

> prescribe regulations which shall establish a procedure similar to that provided by [CAA section 110] under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for [certain air pollutants] … and (B) provides for the implementation and enforcement of such standards of performance.

As noted above, the EPA promulgated the implementing regulations for section 111(d) in 1975, and has revised parts of them since. The regulations set out a multi-step process for the development and approval of state plans, and assign responsibility for the various steps in the process to the EPA or the states. The EPA has followed these regulations in promulgating previous rulemakings under section 111(d).[25] In the present rulemaking, EPA continues to follow them, except that EPA is establishing a different deadline for submission of state plans than what the regulations would otherwise require.[26]

Under the implementing regulations, at the same time or after the EPA proposes and then finalizes standards of performance for sources in a source category under section 111(b), the EPA must propose and then finalize a "guideline document" with information pertinent to state plans under section 111(d):

> Concurrently upon or after proposal of standards of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information pertinent to control of the designated pollutant form [sic: from] designated facilities. Notice of the availability of the draft guideline document will

[25] These rulemakings are cited above.
[26] The EPA is not re-opening these regulations, although it is revising the deadline for EPA action on state plans.

> be published in the Federal Register and public comments on its contents will be invited. After consideration of public comments and upon or after promulgation of standards of performance for control of a designated pollutant from affected facilities, a final guideline document will be published and notice of its availability will be published in the Federal Register."[27]

The regulations go on to describe the contents of the "guideline document" as including, among other things, an "emission guideline" that incorporates the "best system of emission reduction … adequately demonstrated":

> Guideline documents published under this section will provide information for the development of State plans, such as: * * * *
>
> (5) An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved.* * * *
>
> (6) Such other available information as the Administrator determines may contribute to the formulation of State plans.[28]

The implementing regulations define the "emission guideline" as –

> A guideline set forth in subpart C of this part, or in a final guideline document published under section 60.22(a) which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined

[27] 40 CFR 60.22(a).
[28] *Id*. at 60.22(b).

> has been adequately demonstrated for designated facilities.[29]

In addition, the implementing regulations mandate that for air pollutants that adversely affect public health, the "emission guidelines" must be proposed and finalized with the draft and final guideline document:

> [For air pollutants that have been demonstrated to adversely affect public health], the emission guidelines and compliance times referred to in paragraph (b)(5) of this section will be proposed for comment upon publication of the draft guideline document, and after consideration of comments will be promulgated in subpart C of this part with such modifications as may be appropriate.[30]

With this proposed rulemaking, the EPA is complying with these regulatory provisions. This proposed rulemaking follows the proposal of standards of performance for newly constructed affected sources in the January 2014 Proposal, and is concurrent with the proposal of standards of performance for modified and reconstructed affected sources. This proposed rulemaking – including the preamble and the supporting documents -- comprise the "draft guideline document." The documents contain the "information for the development of State plans" described in the regulations. This information includes descriptions as well

[29] 40 CFR 60.21(e).
[30] *Id.* at 60.22(c).

as technical and economic evaluations of the four building blocks. This information also includes the EPA's application of the BSER to each state, and the EPA's calculation of the resulting proposed state goals. These state goals comprise the proposed "emission guidelines." In addition, the preamble and supporting documents propose the "time within which compliance with emission standards of equivalent stringency can be achieved," which are the periods of 2020-2029 for interim compliance, and the subsequent period for final compliance, and provide other information.

VI. Best system of emission reduction adequately demonstrated and standards of performance

In this section we discuss our interpretation of the CAA section 111(d)(1) and (a)(1) provisions that require the state plans to establish, for "any existing source," "standards of performance," and that define the latter term to mean, in general, emission standards that "reflect the degree of emission limitation achievable through the application" of the "best system of emission reduction … adequately demonstrated" (BSER).

In subsection A of this section, we explain these section 111(d)(1) and 111(a)(1) provisions and summarize key parts of the applicable case law.

In subsection B, we describe our proposed two alternative determinations for the BSER. We note that each alternative includes two main components. One component, for each alternative, is efficiency improvements that coal-fired power plants can make to their operations and equipment (which we call building block 1). For the first type of BSER, the remaining component is, in general, increased zero- or low-emitting generation in specified amounts (building blocks 2 and 3), and increased demand-side energy efficiency in specified amounts (building block 4), all of which have the effect of displacing generation from the higher-emitting affected sources. For the alternative type of BSER, the remaining component is reduced generation from higher-emitting affected sources in specified amounts, which is the amount that can be replaced by, in general, increased zero- or low-emitting generation and eliminated by increased demand-side energy efficiency. After we explain these alternatives, we go on to discuss why each alternative is a "system of emission reduction," and why we propose to determine that each system is the "best" that is "adequately demonstrated."

In subsection C, we discuss our interpretation of the requirement that each state must develop a plan that establishes for "any existing source" "standards of performance," that is, emission standards that "reflect the degree of emission limitation achievable through the application of the [BSER]." We explain that once the EPA determines the BSER, it undertakes "the application of the [BSER]" to each state's set of sources on a state-wide basis, and thereby determines the "emission limitation achievable," which we term the state goal, and which in turn becomes the required emission performance level that the state plan must achieve. The state must then develop its plan by identifying emission standards for its affected EGUs -- and, in the case of a state that adopts the portfolio approach, by identifying other obligations on other affected entities -- that in total, achieve the required emission performance level. Through this process, the state plan may meet the requirements of sections 111(d)(1) and (a)(1) to "establish[] standards of performance for any existing source" because it imposes, on each of its affected sources, emission standards that "reflect [that is, embody or represent] the degree of [that is, the part of] emission limitation achievable through the

application of the best system of emission reduction … adequately demonstrated" [that is, the state's required emission performance level].

A. CAA requirements for standards of performance and BSER

In this subsection, we explain the relevant provisions of sections 111(d)(1) and 111(a)(1) and summarize key parts of the applicable case law.

The EPA's explanation for this BSER proposal begins with the key statutory provisions in CAA sections 111(d)(1) and 111(a)(1). Section 111(d)(1) requires that a state plan "(A) establish[] … standards of performance for any existing source" and "(B) provide[] for the implementation and enforcement of such standards." Section 111(a)(1) defines a "standard of performance" as --

> a standard for emissions of air pollutants which reflects 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.

Several points should be made about the BSER. By its terms, it is a "system of emission reduction" that is both the "best" and "adequately demonstrated." The CAA does not define the term, "system," and as a result, that term should be given its ordinary, everyday meaning: "a set of

things working together as parts of a mechanism or interconnecting network; a complex whole."[31] In addition, the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit or Court) has handed down case law over a 40-year period that interprets the requirements that the "system of emission reduction be the "best" and be "adequately demonstrated."[32] Under this case law, the criteria for the EPA to use in determining whether the system is the "best" include the following key considerations, among others:

- The system of emission reduction must be technically feasible.[33]
- The EPA must consider the amount of emissions reductions that the system would generate.
- The costs of the system must be reasonable. The EPA may consider the costs on the source level, the industry-wide level, and, at least in the case of the

[31] *Oxford Dictionary of English* (3rd ed.) (published 2010, online version 2013) http://www.oxfordreference.com.mutex.gmu.edu/view/10.1093/acref/9780199571123.001.0001/acref-9780199571123

[32] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974); *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, (D.C. Cir. 1973), *cert. denied, Appalachian Power Co. v. EPA*, 416 U.S. 969 (1974); *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981); *Portland Cement Ass'n v. EPA*, 665 F.3d 177 (D.C. Cir. 2011).

[33] The case law may be read to treat technical feasibility as the measure for whether the standard of performance is "achievable," Essex Chemical Corp. v. Ruckelshaus, 486 F.2d at 427, not as a criterion for whether the system of emission reduction is the "best system of emission reduction … adequately demonstrated." However, for present purposes, we refer to technical feasibility as another of the criteria for the BSER.

power sector, on the national level in terms of the overall costs of electricity and the impact on the national economy over time.[34]

- The EPA must also consider that CAA section 111 is designed to promote the development and implementation of technology.[35]

- The EPA must also consider energy impacts, and, as with costs, may consider them both on the source level and on the nationwide structure of the power sector over time.

Importantly, the EPA has discretion to weigh these various considerations, may determine that some merit greater weight than others, and may vary the weighting, depending on the source category.

In determining whether a system is "adequately demonstrated," the EPA is to look forward toward what may

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[34] *See Sierra Club v. Costle*, 657 F.2d 298, 330-31, 337-39 (D.C. Cir. 1981). As discussed in the January 2014 Proposal, the D.C. Circuit's case law formulates the cost consideration in various ways: the costs must not be "exorbitant[]", *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) *cert. denied, Appalachian Power Co. v. EPA,* 416 U.S. 969 (1974), *see Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999); "greater than the industry could bear and survive," *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975); or "excessive" or "unreasonable." *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981). In the January 2014 Proposal, EPA stated that "these various formulations of the cost standard ... are synonymous," and, for convenience, EPA used "reasonableness" as the formulation. EPA takes the same approach in this rulemaking.

[35] *See* 79 Fed. Reg. at 1,465/1-2 (discussing case law and legislative history that includes technological development as a consideration in the determination of BSER, including *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981)).

fairly be projected for the regulatory future, rather than determining what is available now. In the D.C. Circuit's first decision under section 111, *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973), the Court explained:

> Section 111 looks toward what may fairly be projected for the regulatory future, rather than the state of the art at the present . . . . The Senate Report made clear that it did not intend that the technology "must be in actual routine use somewhere." . . . The Administrator may make a projection based on existing technology, that that projection is subject to the restraints of reasonableness and cannot be based on "crystal ball" inquiry. . . . [T]he question of availability is partially dependent on "lead time", the time in which the technology will have to be available.[36]

The forward looking nature of determining whether a system is adequately demonstrated is particularly relevant for this proposal given the lengthy period for implementing state plans that the EPA is proposing. The EPA discussed the CAA requirements and Court interpretations of the BSER at length in the January 2014 Proposal,[37] and incorporates by reference that discussion in this rulemaking.

It should be noted that the EPA may identify as the best system of emission reduction adequately demonstrated

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[36] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391-92 (D.C. Cir. 1973) (citations omitted).
[37] *See* 79 Fed. Reg. at 1,462/1 – 1,467/3.

as the BSER a system that would form the basis for emission standards that could be achieved by some, but not necessarily all, of the existing sources in the source category. This approach is consistent with the technology-forcing purposes of section 111, as well as the fact that under section 111(d)(1), the state retains authority, "in applying a standard of performance to any particular source ... to take into consideration, among other factors, the remaining useful life of the ... source...."[38]

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[38] The EPA discussed this issue in connection with new sources in the recently proposed NSPS for CO_2 emissions from fossil fuel-fired EGUs, 79 Fed. Reg. 1430, 1466/3 (Jan. 8, 2014). With respect to existing sources, a commentator has stated:

> There is no statutory provision or direct precedent under § 111(d) requiring EPA to demonstrate that emission limits are achievable by every source subject to an [standard of performance for existing sources]. Moreover, since the trigger for implementing § 111(d) is an NSPS under § 111(b), Congress arguably contemplated that, once EPA has identified BSER for new plants, it should raise the performance of the existing fleet with the goal of approaching new source levels at existing plants. In this reading, 111(d) would have a technology-forcing thrust, tempered by the performance and cost constraints at existing plants but nonetheless raising the bar significantly for the existing fleet. From this perspective, EPA could argue that "adequately demonstrated" means achievable at a reasonable cost by the more modern, better performing coal and gas units, not by all plants [citing Reinforcing this approach is the fact that cost is not determinative in

B. Best system of emission reduction adequately demonstrated

In this subsection, we describe our two alternative proposed determinations for the BSER and explain why each is a "system of emission reduction," and why each system is the "best" that is "adequately demonstrated."

1. Introduction and overview

The EPA's BSER proposal in this rulemaking recognizes, and is based in part on, the interconnected nature of the electrical generating system, which, among other things, means that generation at one EGU can substitute for generation at another. The importance of the interconnected nature of the grid in facilitating CO_2 emissions reductions is evident in the long history of reliance on it to provide least-cost dispatch, the more recent history of implementing air pollutant emissions reductions, and the still more recent history of implementing CO_2 emissions reductions at the company, state, and regional level.

> defining a "standard of performance" under § 111(a) but only must be "taken into account" ….

Sussman, R., "Power Plant Regulation Under the Clean Air Act: A Breakthrough Moment for U.S. Climate Policy?," *Virginia Environment Law Journal*, 32:97 (2014), at 123 (citations omitted).

In this rulemaking, the EPA proposes to determine the "best system of emission reduction … adequately demonstrated" on a state-by-state basis. Moreover, the EPA proposes to determine the BSER based on four "building blocks," some of which rely on the interconnected nature of the electricity generating grid:

> Building block 1: Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.
>
> Building block 2: Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction).
>
> Building block 3: Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
>
> Building block 4: Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

As discussed in the preamble, with these building blocks in mind, we are proposing two alternatives for the BSER, each of which is based on methods for reducing fossil fuel-fired EGUs' air pollutants that states and sources have already implemented. The first approach is that the BSER is the combination of building blocks 1 through 4. Building block 1 is a set of operational improvements and

equipment upgrades that the affected sources may undertake to improve their efficiency and reduce their emissions rate. Building blocks 2, 3 and 4 are sets of measures that, in general, increase zero- or low-emitting generation in specified amounts and increased demand-side energy efficiency in specified amounts, all of which, due to the interconnected nature of the grid, result in drawing utilization away from higher-emitting fossil fuel-fired EGUs, thereby lowering those EGUs' emissions. The second approach is that the BSER is building block 1 (heat rate improvements) combined with reduced generation from fossil fuel-fired EGUs in the amount, calculated on a statewide basis, that can be replaced by, in general, increased zero- or low-emitting generation and avoided by increased demand-side energy efficiency. The EPA proposes that each of these alternatives may be considered to be a "system of emission reduction," and that each meets the criteria, set out in CAA section 111(a)(1) and the case law, to qualify as the "best" system that is "adequately demonstrated."

2. Background: Interconnected nature of the electricity system

Central to our BSER determination is the fact that the nation's electricity needs are being met, and have for many decades been met, through a grid formed by a network

connecting groups of EGUs with each other and, ultimately, with the end-users of electricity. We discuss this nature of the electricity system at length in the preamble and, for convenience, summarize that discussion here.

Through the interconnected grid, fungible products – electricity and electricity services – are produced and delivered by a diverse group of EGUs operating in a coordinated fashion in response to end-users' demand for electricity. Because the electricity grid operates through the interconnection of multiple EGUs and favors least-cost generation, owners and operators of generators have been able to assure the stability of electricity generation and the reliable delivery of electricity to users at least cost (subject to certain reliability, environmental and other constraints). The fact that generation at one EGU can be substituted for generation at another allows operators to utilize their least-cost assets first, and hold their higher-cost assets in reserve, thereby assuring that the system achieves the objectives of providing reliable and least-cost electricity service.

In recent years, the ability to shift between different generation assets on the grid has also facilitated the achievement of environmental objectives, including the reduction of emissions of nitrogen oxides,

sulfur dioxide, and particulate matter -- which, among them, worsen acid deposition and jeopardize the attainment and maintenance of national ambient air quality standards – as well as hazardous air pollutants. Regulation of those air pollutants tends to increase the relative cost of electricity from higher-emitting generation assets. Because EGU operators have the ability to use the grid as an interchange for shifting levels of generation among several facilities, the higher costs of higher-emitting assets must be considered, along with fuel costs and other marginal costs, in determining the extent to which those assets are utilized. The amount of their utilization affects the amount of their emissions.

Most recently, states and companies seeking specifically to achieve CO_2 emissions reduction objectives have also relied on the shifting of generation between and among EGUs to achieve those emissions reduction objectives. In fact, as the preamble notes, there are many cases in which companies have reduced emissions through shifting generation away from higher emitting units to lower- or zero-emitting units, or through reducing overall electric demand through demand-side energy efficiency measures. In some cases, this has occurred in response to goals set at the company level: some companies have established a

single, company-wide emission target, and then have used combinations of strategies such as fuel switching, increased renewable or nuclear generation, and increased energy efficiency, to achieve those goals. In other cases, this has occurred in response to goals set at the state level: for example, California enacted its Global Warming Solutions Act in 2006 (AB 32), requiring the state to reduce its GHG emissions to 1990 levels by 2020 and 80 percent below 1990 levels by 2050,[39] through a suite of mechanisms that include energy efficiency programs, renewable energy programs and an economy-wide cap and trade program, along with other programs.[40] Similarly, nine northeast and mid-Atlantic states participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based emissions budget trading program that sets an aggregate limit on CO_2 from fossil fuel fired power plants in the participating states. These examples demonstrate that it is appropriate to base the BSER at least in part on the combination of measures in building blocks 2, 3, and 4, and

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[39] State of California Global Warming Solutions Act of 2006, Assembly Bill 32, Chapter http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf

[40] *See* Cal. Air Res. Bd., Climate Change Scoping Plan 31-32, 41-46 (2008), *available at:* http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf.

that this component of such a system is adequately demonstrated.

In all of these instances, companies' choices and policies implemented by states may impact decisions about dispatching of lower instead of higher emitting generating units both as part of the short term dispatch process and as part of longer term business planning processes. The proposed emission guidelines, including the temporal flexibility that the guidelines incorporate, allow states and EGUs to implement a variety of mechanisms that can reduce emissions both as part of those shorter term dispatch decisions and as part of longer term business planning processes.

In this rulemaking, the EPA is building on these company, state, and regional approaches by continuing to rely on the interconnected nature of the grid to achieve, on a nationwide basis, the important objective of significant amounts of CO_2 reductions from fossil fuel-fired EGUs. The EPA is doing so by proposing that the BSER should be based on a combination of the implementation of heat improvement measures for fossil fuel-fired steam generating units (building block 1) to reduce their emissions, as well as the implementation of other measures that are associated with reduced emissions from those EGUs. The latter include

substituting generation at higher emitting sources with increasing generation at less carbon-intensive EGUs, using expanded amounts of low- or zero-carbon generating capacity connected to the electric grid, and using electricity more efficiently to reduce the total demand for electricity (building blocks 2, 3 and 4, respectively).

In determining the BSER, it is significant that CO_2 is a global pollutant, and therefore the location of the emissions (or emission reductions) does not affect the impact on climate change of an amount of emissions generated at any given source in any one location.[41] The fact that CO_2 becomes well-mixed in the atmosphere means that CO_2 emissions may be reduced anywhere within the electricity grid and still achieve the intended climate benefits. This allows the EPA to determine that a system

[41] By analogy, because the problem of acid deposition is caused by EGU emissions of nitrogen oxide and sulfur dioxide over a wide geographic area, Title IV of the Clean Air Act established a national emissions trading program that addresses that problem by reducing the total amount of those emissions, but without regard to the particular location of those emissions (or emissions reductions). In contrast, other air pollutants have adverse health and welfare effects in the locality where they are emitted, and as a result, geographic constraints on emissions trading are necessary. *See* CAA section 173(c)(1) (limiting offsets for air pollutants subject to new source review requirements to emissions reductions from sources in certain nonattainment areas).

is the "best" system based on the total emission reductions the system would achieve, rather than basing the determination on the emission reductions achieved at each individual affected source.

3. First Approach to the BSER: Building blocks 1, 2, 3, and 4 in combination

Under the EPA's first approach to determining the BSER, the EPA is proposing that the BSER is the combination of building blocks 1 through 4. As discussed in the preamble, under the EPA's proposed approach to determining the BSER, the measures in building block 1, which entail improvements in the efficiency of the affected EGUs' equipment or processes, meet the criteria to qualify as a part of the BSER. Further elaboration of this point here is not necessary. In addition, in the preamble, we explain why all four building blocks in combination meet the criteria to qualify as the BSER, and further elaboration of this latter point here is also not necessary. Instead, this discussion will focus on building blocks 2, 3, and 4.

Under this first approach to the BSER, the "best system of emission reduction … adequately demonstrated" also includes the measures in building blocks 2, 3 and 4 for the affected fossil fuel-fired steam generating boilers, and building blocks 3 and 4 for the fossil fuel-

fired combustion turbines. In this section, we first explain why the measures in these building blocks are part of a "system of emission reduction," and then why that system is the "best" system that is "adequately demonstrated."

In brief, building blocks 2, 3, and 4 are part of a "system of emission reduction" because that phrase, in the context in which it is used in section 111 and by its terms, is broad enough to apply to the measures in the building blocks, in light of the integrated nature of the electricity grid. Through the integrated grid, the measures reduce overall demand for, and therefore utilization of, higher emitting, fossil fuel-fired EGUs, which, in turn, reduces CO_2 emissions from those EGUs. The measures in the building blocks are part of the "best" system that is "adequately demonstrated" because they meet the criteria in section 111(a)(1) and the case law for BSER and they are well-established.

a. ***"[S]ystem of emission reduction"***

The EPA's proposal that in this rulemaking, the "system of emission reduction" includes the measures in building blocks 2, 3, and 4 is grounded in the EPA's interpretation of the key CAA provisions: section 111(d)(1), which requires that each state plan "establish[]

standards of performance for any existing source" for certain types of air pollutants; and section 111(a)(1), which defines a "standard of performance" as "a standard for emissions … which reflects the degree of emission limitation achievable through the application of the best system of emission reduction … adequately demonstrated." As explained next, the EPA's interpretation may be justified under either a *Chevron* step 1 or *Chevron* step 2 interpretation.

i. Chevron step 1 interpretation

The starting point for our analysis is the phrase, "system of emission reduction," which serves as the basis for the "standard for emissions." As noted above, the CAA does not define the term, "system," and as a result, that term should be given its ordinary, everyday meaning: "a set of things working together as parts of a mechanism or interconnecting network; a complex whole."[42] This definition is broad. It encompasses virtually any "set of things" that reduce emissions. Moreover, no other provisions in the definition of "standard of performance" include any other constraints on the type of "things" that may serve as the

[42] *Oxford Dictionary of English* (3rd ed.) (published 2010, online version 2013) http://www.oxfordreference.com.mutex.gmu.edu/view/10.1093/acref/9780199571123.001.0001/acref-9780199571123

basis for the standard for emissions. The only constraints are the qualifiers "best" and "adequately demonstrated," but these do not constrain the type of "things" that could be a "system of emission reduction," only whether a particular "thing" qualifies as the "best" "system of emission reduction" that is "adequately demonstrated" (it must be, among other things, technically feasible and of reasonable cost). Thus, the "system of emission reduction" may include anything that reduces emissions, ranging from add-on controls applied to the affected sources' smokestacks to control emissions, to measures that replace production or generation at the affected sources and thereby reduce emissions from those sources.

Moreover, the context in which "standard of performance," which includes "system of emission reduction," is found does not add additional constraints. As noted above, section 111(d)(1) requires that state plans establish "standards of performance for any existing source," and in the preamble, we solicit comment on the interpretation of that phrase. Among other things, we solicit comment on whether the standards of performance must apply directly to the affected sources and only to the affected sources, in which case the affected sources would bear the legal liability for the entire amount of emission

reduction requirements; or whether, instead, the standards of performance may apply to other entities whose actions would reduce generation, and thus emissions, from the affected sources. Under either of those interpretations, there is nothing in that phrase that limits the type of "system of emission reduction" that, if it is the "best" that is "adequately demonstrated," may furnish the basis for the standards for emissions. That is, even if that phrase -- "standards of performance for any existing source" -- is interpreted to mean that the standards of performance must apply directly to, and only to, the affected sources, that application of the standards of performance does not limit the scope of the type of "system of emission reduction" that may serve as the basis for the standards for emissions. Any "system of emission reduction" that reduces the emissions of the affected sources may serve as the basis for the standards for emissions, as long as, again, it is the "best" that is "adequately demonstrated." For these reasons, the scope of the type of "system of emission reduction" that may be considered is broad.

Interpreting the "system of emission reduction" in this manner is also consistent with the scope of the state plans. Under section 111(d)(1), a state plan must

"establish[] standards of performance" and "provide[] for the implementation and enforcement of such standards of performance." At the state's discretion, measures in building blocks 2, 3, and 4 may be included in state plans either through the portfolio approach or as measures that "provide[] for the implementation" of standards of performance that limit emissions from affected EGUs.

Based on these interpretations, for existing sources in the electric utility industry, we propose that the term "system of emission reduction" is sufficiently broad to include the measures in building blocks 2, 3, and 4 because they are part of the interconnected electricity sector and result in reduced utilization, and therefore reduced emissions, from the higher emitting fossil fuel-fired power plants. This proposed reading is clear as a matter of *Chevron* step 1 because of the breadth of the term, "system," in the context in which it is found.

ii. Chevron step 2 interpretation

Moreover, even if the term, "system of emission reduction" is not considered to be clear as a matter of *Chevron* step 1 to include the measures in building blocks 2, 3, and 4, then the EPA's interpretation of the term to include those measures is valid as reasonable construction

under *Chevron* step 2. There are several reasons for interpreting "system of emission reduction" in this way.[43]

(I). Legislative history of "standard of performance"

First, the legislative history of the definition of "standard of performance," including the phrase "best system of emission reduction … adequately demonstrated," makes clear that the "system of emission reduction" is broader than a technological system. As enacted by Congress in the 1970 CAA Amendments, section 111(a)(1) defined the term "standard of performance" as, in relevant part --

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction … adequately demonstrated.

In the 1977 CAA Amendments, Congress changed this definition to require that for new sources, the standard must, in relevant part, "reflect the degree of emission limitation … achievable through application of the best

[43] *See EPA v. EME Homer City Generation, L.P.,* No. 12-1182, slip op. at 22 (U.S. April 29, 2014) (after explaining why the text of the CAA "did not answer" the largely technical question of how EPA should allocate each state's responsibility for the tangle of potentially "significant" upwind-to-downwind air pollution contributions, stating: "Under *Chevron*, we read Congress' silence as a delegation of authority to EPA to select from among reasonable options.")

technological system of continuous emission reduction … adequately demonstrated;" and for existing sources, the standard must, in relevant, "reflect[] the degree of emission reduction achievable through the application of the best system of continuous emission reduction … adequately demonstrated…." (Emphasis added.)[44] In the 1990 CAA Amendments, Congress again changed this definition, this time to reinstate the definition as found in the 1970 CAA Amendments (with some revisions not here relevant). That is, Congress repealed the requirements added in the 1977 CAA Amendments that the "system" be, in the case of new sources, "technological."

These amendments make clear that the "system[s] of emission reduction" upon which the section 111(d) standards of performance may be based are not limited to technological systems. Even when, in the 1977 CAA Amendments, Congress limited the systems that could provide the basis for the standards of performance for new sources to technological systems, Congress did not establish that limit on the systems for existing sources. Moreover, the 1977 House-Senate Conference Committee report stated that

[44] The 1977 CAA Amendments also revised section 111(a)(1) to require that the standards of performance for fossil fuel-fired sources require a percentage reduction in emissions (the "percentage reduction" requirement).

for existing sources, the standards of performance were to be based on the "best available means of emission control (not necessarily technological)…."[45]

(II). Pollution prevention

In addition, interpreting the term "system of emission reduction" broadly to include the building blocks is consistent with a primary purpose of the CAA, which is encouraging pollution prevention, including assuring that states fulfill their role in developing pollution prevention measures. CAA section 101(c) states that "[a] primary goal of [the Clean Air Act] is to encourage or otherwise promote reasonable Federal, State, and local governmental actions, consistent with the provisions of this chapter, for pollution prevention." CAA section 101(b)(4) adds that one of "the purposes of [title I of the CAA, which includes section 111] are … (b) to encourage and assist the development and operation of regional air pollution prevention and control programs." Indeed, in the U.S. Code, in which the CAA is codified as chapter 85, the

[45] "Joint Explanatory Statement of the Committee of Conference," *reprinted in* Congressional Research Service, *A Legislative History of the Clean Air Act Amendments of 1977*, vol. 3 at 502, 509 (1978) (*1977 Legislative History*). The House Committee Report included the same statement. *See* H. Rep. 95-294 at 195, *reprinted in 1977 Legislative History,* vol. 4 at 2465, 2662.

CAA is entitled, "Air Pollution Prevention and Control." CAA section 101(a)(3) describes "air pollution prevention" as "the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source," and adds: "The Congress finds -- … (3) that air pollution prevention … and air pollution control at its source is the primary responsibility of States and local governments."

The measures in building blocks 2, 3, and 4 all qualify as types of "pollution prevention" because they are "measures" that "reduc[] or eliminate[e] … the amount of pollutants produced or created at the [fossil fuel-fired affected] source[s]." It is reasonable to interpret the section 111 provisions at issue in this rulemaking in light of these section 101 provisions, and this supports the reasonableness of interpreting the broad term found in section 111(a)(1), "system of emission reduction," to include the pollution prevention measures in building blocks 2, 3, and 4.

(III). Title IV

The breadth of the term, "system of emission reduction" is further confirmed by reference to certain provisions of CAA Title IV. In Title IV, Congress established the program that regulates fossil fuel-fired

power plants to reduce their emissions of the precursers to acid deposition, including reducing sulfur dioxide (SO_2) emissions in two phases, and reducing nitrogen oxides (NOx) emissions. Congress enacted Title IV as part of the 1990 CAA Amendments, at the same time that Congress revised the definition of "standard of performance" to generally return it to its 1970-vintage reading. In certain respects, section 111 and Title IV are related because both apply to fossil-fuel fired EGUs, and Congress recognized the relationship in several Title IV provisions.[46]

One contrasting provision in Title IV is section 407(b)(2), which requires the EPA to base the NOx emission limits for certain types of boilers "on the degree of reduction achievable through the *retrofit* application of the best system of continuous emission reduction...;" and further requires the EPA to revise previously promulgated

[46] *See, e.g.,* CAA section 402(8), 405(c)(2). In fact, in the 1990 CAA Amendments, Congress based its decision to repeal the percentage reduction requirements added in the 1977 CAA Amendments to the section 111(a)(1) definition of "standard of performance" for new fossil fuel-fired sources at least in part on the grounds that provisions of Title IV would cap SO_2 emissions from fossil-fuel fired EGUs, and, further, Congress conditioned that repeal on the continued applicability of the SO_2 cap, so that if the cap were eliminated, the repeal would, by operation of law, be eliminated. *See* Pub. L. 101-549 section 403(b), S. Rep. 101-228, at 338, *reprinted in* 1990 Legislative History 8338, 8678 (1990 Senate Committee Report).

emission limits for certain types of boilers "to be more stringent if the [EPA] determines that *more effective low NOx burner technology* is available." (Emphasis added.) These narrower specifications for the basis of the Title IV emissions limits make clear that Congress knew how to constrain the basis for emission limits to the results of certain technology, and that its choice to base the section 111(d) standards of performance on a "system of emission reduction" indicates its intent to authorize a broader basis for those standards.

Other provisions in Title IV and their legislative history provide further support for interpreting the term, "system of emission reduction" to include building blocks 2, 3, and 4. In designing Title IV, Congress recognized the integrated nature of the electricity sector and how that integration could be harnessed to reduce air pollutant emissions; and, in fact, Congress included provisions to encourage re-dispatch to lower emitting sources, renewable energy, and demand-side energy efficiency, all of which are measures in those building blocks. Specifically, Congress added into the "purposes" provision of Title IV, the statements that in addition to the reducing the adverse effects of acid deposition –

> It is also the purpose of [Title IV] to encourage energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy, consistent with the provisions of [Title IV], for reducing air pollution and other adverse impacts of energy production and use…."[47]

Congress recognized that the very structure of Title IV – which imposed a marketable trading system under which affected sources were required to have an allowance for each ton of SO_2 emitted and could buy and sell allowances on the open market -- encouraged such measures as demand-side energy efficiency and re-dispatch by lower-emitting sources. The 1990 Senate Committee Report explained:

> [T]he incentives created by the allowance market should stimulate innovations and the technologies and strategies used to reduce emissions…. [T]he allowance market should encourage sources to exploit *energy efficiency*, enhanced emission reduction or control technologies….; fuel-switching and *least-emissions dispatching* in order to maximize emission reductions."[48]

In addition, Congress incorporated into Title IV specific incentives to further encourage electric utilities (defined as entities that sell electricity[49]) to reduce

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[47] CAA section 401(b). *See* H. Rep. 101-490 Part 1 at 369-70 (1990 House Comm. Rep.), *reprinted in* "A Legislative History of the Clean Air Act Amendments of 1990," *Congressional Research Service* (1993) (1990 Legislative History), vol. II, at 3021, 3393-94.

[48] 1990 Senate Committee Report at 316, *reprinted in* 1990 Legislative History, vol. V, at 8656 (emphasis added).

[49] CAA section 404(f)(1)(C).

their emissions through demand-side energy efficiency and renewable energy: Section 404(f)-(g) provided a special reserve of allowances to be allocated to electric utilities "for each ton of SO_2 emissions avoided by an electric utility … through the use of … energy conservation measures or … renewable energy." In fact, in adopting these provisions, Congress explicitly recognized the integrated nature of the electricity sector: As one of the conditions for eligibility for this special reserve of allowances, the utility must "ha[ve] adopted and is implementing a least cost energy conservation and electric power plan which evaluates a range of resources, including new power supplies, energy conservation, and renewable energy resources, in order to meet expected future demand at the lowest system cost."[50]

These CAA provisions and the accompanying statements in the legislative history make clear that in enacting the Title IV provisions to reduce SO_2 and NO_x emissions from fossil fuel-fired EGUs, Congress viewed the electricity sector as interconnected and considered re-dispatch to lower emitting sources, renewable energy, and demand-side energy efficiency as methods to reduce those emissions.

[50] CAA section 404(f)(2)(B)(iii)(I).

All this supports the reasonableness of the EPA's proposed interpretation that the "system of emission reduction" that serves as the basis for "standards of performance" for CO_2 emissions from fossil fuel-fired EGUs may include those same measures, that is, building blocks 2, 3, and 4 (re-dispatch; low- or zero-emitting generation, including renewables; and demand-side energy efficiency, respectively.)

(IV). EPA Precedent

In the past, the EPA has promulgated rules under CAA section 111(d), in conjunction with CAA section 129, that were based on measures that are similar to some of the measures in the building blocks that EPA proposes as the basis for the regulatory requirements in this rulemaking. For example, the EPA has authorized states to allow large municipal waste combustors to average their emission rates and trade NOx emission credits,[51] and have required the

[51] *See* "Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources; Municipal Waste Combustors," 60 Fed. Reg. 65,387 (Dec. 19, 1995) (trading rules codified in 40 C.F.R. section 60.33b(d)(1)-(2)). EPA also authorized an emission trading program in the Clean Air Mercury Rule. *See* "Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, Final Rule," 70 Fed. Reg. 28,606 (May 18, 2005) *vacated on other grounds by New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008), *cert denied sub nom. Util. Air Reg. Grp. v. New Jersey*, 555 U.S. 1169 (2009); "Standards of Performance for New Stationary Sources and

owners of certain waste incineration facilities to take steps to reduce the amount of waste that the facilities combust.[52]

(V). Other considerations

It should also be noted that a number of commentators in the private sector and academia have indicated support for interpreting the term, "system of emission reduction" to incorporate measures such as re-dispatch, renewable

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Emission Guidelines for Existing Sources; Municipal Waste Combustors," 60 Fed. Reg. 65,387 at 28616-24, (Dec. 19, 1995).

[52] *See, e.g.*, Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Hospital/Medical/Infectious Waste Incinerators, 62 Fed. Reg. 48,348, 48359 (Sept. 15, 1997); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, 65 Fed. Reg. 75338, 75341 (Dec. 1, 2000).

energy, and demand-side energy efficiency.[53] Some stakeholders have as well.[54]

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[53] *See* Nordhaus R., Gutherz I., "Regulation of CO_2 Emissions from Existing Power Plants Under section 111(d) of the Clean Air Act: Program Design and Statutory Authority," *Environmental Law Reporter,* 44: 10366, 10384 (May 2014) ("strong arguments for" interpreting "system" to include measures such as the addition of new zero-carbon generating capacity and increases in end-user energy efficiency); Sussman R., "Power Plant Regulation Under the Clean Air Act: A Breakthrough Moment for U.S. Climate Policy?" *Virginia Environment Law Journal*, 32:97, 119 (2014) ("EPA would seem to have discretion to define 'system' to include any mix of strategies effective in reducing emissions."); Konschnik K., Peskoe A., "Efficiency Rules: The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants," *Harvard Law School Environmental Law Program – Policy Initiative* 4 (March 3, 2014) (EPA is authorized to "consider[] … the entire [electricity grid] system when setting performance standards."); Monast J., Profeta T., Pearson B., Doyle J., "Regulating Greenhouse Gas Emissions From Existing Sources: Section 111(d) and State Equivalency," Environmental Law Reporter, 42: 10206, 10209 (March 2012) ("Demand-side energy-efficiency programs and renewable energy generation may fit within the section 111 framework, however, because both reduce the utilization of power plants …. According to this reasoning, emission reductions are occurring within the source category, because of changes in generation at the power plant.").

[54] Ceronsky M., Carbonell T., "Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants," *Environmental Defense Fund,* at 9 (Oct. 2013), *available at* http://www . edf .org/sites/default/files/111-clean_air_act-strong_flexible_cost-effective_ carbon_pollution_standards_for_existing_power_plants .pdf ; Doniger D., "Questions and Answers on the EPA's Legal Authority to Set 'System Based' Carbon Pollution Standards for Existing Power Plants under Clean Air Act Section 111(d)," *NRDC [Natural Resources Defense Counsel] Issue Brief* (Oct. 2013); "Comments of the Attorneys General of New York, California, Massachusetts, Connecticut, Delaware, Maine, Maryland, New Mexico, Oregon, Rhode Island, Vermont,

In addition to the just-discussed reasons why interpreting the term, "system of emission reduction" to include those measures is a reasonable interpretation under the CAA, that interpretation also is reasonable as a matter of policy, as we discuss extensively in the preamble. To reiterate briefly, including those measures is consistent with the industry's long-standing methods of operating to assure reliability at the least cost, how states have more recently reduced non-greenhouse gas air pollutants from the industry, and, how states and segments of the industry have, still more recently, reduced CO_2 emissions.

b. "Best system of emission reduction … adequately demonstrated"

For the reasons described next, the measures in each of building blocks 2, 3, and 4 qualify as components of the "best system of emission reduction … adequately demonstrated." As noted elsewhere, the D.C. Circuit has interpreted the BSER as "[a]n adequately demonstrated system," and explained that such a system is one that can "be[] shown to be reasonably reliable, reasonably efficient, and … reasonably … expected to serve the

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Washington, and the District of Columbia on the Design of a Program to Reduce Carbon Pollution from Existing Power Plants" (Dec. 16, 2013).

interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[55] In fact, the measures in the building blocks do meet the criteria established by the Court in the section 111 case law. In addition, the measures are "adequately demonstrated" because they have already been implemented in many states, and because they may be undertaken by the affected EGUs in the regulated markets in which they operate, or may be implemented by the states in the state plans.

i. Criteria for the BSER

The measures in building blocks 2, 3, and 4 meet the criteria for inclusion as components of the BSER because they are individually and together technically feasible, and together they achieve significant emission reductions, are not unreasonably costly, and will promote the development and implementation of technology improvements for continued emission reductions.[56] The bases for these

[55] *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d at 427.
[56] As noted above, we are proposing to determine BSER as the combination of all four building blocks, and because we discuss in the preamble the reasons why building block 1 meets the criteria for inclusion in the BSER,and why the BSER is the combination of all four building blocks, we are not further discussing those points here.

conclusions are discussed in detail in the preamble and briefly summarized below.

Building block 2, which entails substituting generation at higher emitting units (fossil fuel-fired steam generating units) by shifting to generation at lower-emitting affected sources (existing NGCC units) is technically feasible because the NGCC units are already providing electricity to the grid and have sufficient capacity to generate the additional amount of electricity that would substitute for the generation at fossil fuel-fired steam generating units. Re-dispatch is already widely used (usually more in response to fuel price signals than as a CO_2 mitigation measure), including by companies that own both coal- and natural-gas-fired EGUs. It should be noted that there are several mechanisms through which states could cause re-dispatch to occur. First, a state could use its permitting authority to impose limits on the hours of operation (or emissions) of individual steam generating units over a given time period. Second, a state could change the relative costs of generation for more carbon-intensive and less carbon-intensive generating units by imposing a cost on carbon emissions. A state could do so through any of several market-based mechanisms. One would be to adopt an allowance-based system. An example is the

Regional Greenhouse Gas Initiative, an allowance-based system in which sources purchase allowances in periodic auctions. Another way would be through a tradable emission rate system, under which the state would impose an emission rate on the steam generating unit that the unit could meet only by purchasing the right to average its emission rate with a unit with a lower rate, such as an NGCC unit. Most broadly, an allowance system would provide the greatest incentive for the most carbon-intensive affected sources to reduce emissions as much as possible so as to reduce their need to purchase allowances (or to allow them to sell un-needed allowances), and the same would be true for a tradable emission rate system.

As discussed in the preamble, building block 3, which entails use of new low- and zero-emitting generation, as well as preservation of nuclear capacity that might otherwise be retired, is also technically feasible. The technology for renewable energy is well-established and in use now, and the amount of renewable energy contemplated by the proposal would not impair the reliability of the grid. The nuclear capacity at issue either is already in operation or, in the case of new nuclear capacity under construction, has long been known to grid operators for planning purposes. The measures in building block 3 may be

implemented in different ways, including market mechanisms. In particular, markets for renewable energy certificates, which facilitates investment in renewable energy, are already well-established. In addition, as noted above with re-dispatch, an allowance system or tradable emission rate system would provide incentives for sources to reduce their emissions as much as possible, including by substituting their generation with generation from renewable energy.

As for building block 4, as discussed in the preamble, numerous state and utility programs have demonstrated that improvements in demand-side energy efficiency are technically feasible at the levels contemplated in the proposal. An allowance system or tradable emission rate system would provide incentives that promote the measures in building block 4 in the same manner as just discussed for other building blocks.

For the reasons discussed in the preamble, the combination of building blocks 2, 3, and 4, along with building block 1, also meet the criteria to qualify as the BSER. The level of CO_2 emissions reduction they achieve is significant, which is appropriate because of the severity of the risk to public health and the environment of climate change, and the magnitude of both the amount of emissions

reductions needed and the amount of CO_2 emissions from fossil fuel-fired power plants.

In addition, based on the measures in building blocks 2, 3, and 4 combined, the proposed levels of reduced generation are not unreasonably costly for the affected source category or the nation-wide electricity system. These levels do not have adverse effects on the overall energy system. Electricity consumers would continue to have access to the electricity they need under these building blocks, although they would need less energy for the same amount of economic activity as a result of the measures in building block 4. Additionally, the measures in building blocks 2, 3, and 4 would improve the electricity system by reducing its carbon intensity, as well as other pollutants, allowing consumers to get the same amount of electricity for less environmental harm. Together, these measures would also promote the development and implementation of technology that is important for continued emissions reductions.

ii. Basis for "adequately demonstrated" finding

The measures in building blocks 2, 3, and 4 are "adequately demonstrated" because each of the individual measures is adequately demonstrated, and because it has

been adequately demonstrated that the measures can be taken in combination with each other in a manner consistent with the criteria for determining the BSER.

The measures in building block 1 are adequately demonstrated because they are based on the real-world experience of individual power plants in recent years, as more fully described in the preamble and a technical support document.

The measures in building blocks 2, 3, and 4 are "adequately demonstrated" because, as discussed in the preamble, due to the integrated nature of the electricity system, they have long been relied on to reduce costs in general, assure reliability, and implement pre-existing pollution control requirements in the least cost manner. As also noted in the preamble, some utilities, states and regions are already relying on these measures for the specific purpose of reducing CO_2 emissions from EGUs.

At the same time, as discussed in the preamble, measures in building blocks 2, 3, and 4 may be undertaken, and in fact have been undertaken, by the affected EGUs themselves, which further indicates that these measures are "adequately demonstrated." To achieve the re-dispatch described in building block 2, operators of the affected fossil fuel-fired steam-generating EGUs may reduce

generation, while operators of the affected NGCC units may increase generation to replace that avoided at higher-emitting facilities. Operators of the affected EGUs may invest in, or otherwise acquire power from, the new low- or zero-carbon intensive generation described in building block 3, as well as in many of the demand-side energy efficiency measures described in building block 4.

More specifically, many states maintain a utility regulatory structure under which the utilities that serve end users in the state are vertically integrated, and not only own the EGUs, but often also own renewable energy resources and provide service directly to retail customers. Operators of EGUs, in those circumstances, are well-positioned to undertake the measures in building blocks 3 and 4. In fact, as noted in the preamble, numerous states have already imposed renewable portfolio standards and demand-side energy efficiency requirements on those utilities. As a result, as also noted in the preamble, many companies have already developed integrated resource plans that include re-dispatch from higher-emitting fossil fuel-fired generation to lower-emitting generation, the purchase of renewable capacity or the development of renewable

generation assets, and the implementation of demand-side energy efficiency measures.[57]

Other states have de-regulated their electricity markets[58] and as a result, in some instances, the EGUs in those states are merchant generators that sell to the wholesale electricity market. The EPA believes that markets for acquiring renewable energy resources and for delivering demand-side energy efficiency services are sufficiently well-developed that operators of these EGUs could undertake or acquire those measures as well. For example, merchant generators can invest in NGCC capacity, invest in renewable capacity or purchase renewable energy or renewable energy certificates (representations that a certain amount of energy was produced from renewable sources), as well as purchase demand-side energy efficiency services from energy service companies. The fact that the affected sources may themselves implement or invest in the measures in building blocks 2, 3, and 4 -- which, again, reduce their emissions

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[57] Moreover, in many de-regulated states, forward capacity auctions are used to ensure the ability to meet future demand, and generators may bid into those auctions based on all of their resource portfolio, including renewable energy assets and demand-side energy efficiency projects. This has encouraged generators to undertake the measures in building blocks 3 and 4.

[58] Some states, such as Ohio, have hybrid model that includes elements of a regulated market and a de-regulated market.

-- supports treating those measures as components of the BSER.

Another reason that the measures in building blocks 2, 3, and 4 should be considered "adequately demonstrated" – and wholly apart from the fact that the EGUs may undertake those measures themselves – is based on the fact that CAA section 111(d)(1)(A) provides, by its terms, that the standards of performance that are based on the BSER must be established by the states in state plans. As a result, emissions reduction measures that the states themselves have the authority under state law to put in place may be considered to be part of the BSER. While EGU owners and operators may effectuate such measures directly or indirectly, the states also have authority to enact measures such as dispatch limitations, renewable portfolio standards that require investment in renewable energy resources, as well as demand-side energy efficiency

measures.[59] As noted in the preamble, many states have already done so.[60]

Finally, we note that during the public outreach sessions, stakeholders generally recommended that state plans be authorized to rely on, and that affected sources be authorized to implement, re-dispatch, renewable energy measures and demand-side energy efficiency measures, in order to meet the states' and sources' emissions reduction obligations. The EPA agrees that state plans may include these measures, at least under certain circumstances discussed in the preamble, and that sources may rely on them to achieve required reductions. It is clear that these types of measures are well-accepted by the stakeholders as means to reduce emissions from affected

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[59] It should be noted that under the portfolio approach to the state plan, discussed in the preamble, the entities that undertake some of the measures in, for example, building block 4 may not be the affected EGUs. Regardless of which entities undertake the measures in the building blocks, those measures have the effect of reducing CO_2 emissions from fossil fuel-fired EGUs, and therefore each of the building blocks remains part of a "system" of emission reduction for those EGUs.

[60] More than half the states have established renewable portfolio standards (RPS) that require minimum proportions of electricity sales to be supplied with generation from renewable generating resources. More than 20 states have energy efficiency resource standards (EERS) that require utilities to effectuate a certain amount of savings in electricity demand each year or cumulatively. Database of State Incentives for Renewables & Efficiency (DSIRE), http://www.dsireusa.org/summarymaps/index.cfm?ee=0&RE=0.

sources. The fact that state plans and sources would be expected to use these types of measures to reduce emissions supports the view that these measures are part of a "system of emission reduction" for those sources that the EPA may evaluate against the appropriate criteria to determine whether they comprise the "best system of emission reduction … adequately demonstrated."

c. Stakeholder concerns

As noted above, some stakeholders have argued that section 111(a)(1) authorizes the EPA to identify re-dispatch, low- or zero-emitting generation, and demand-side energy efficiency measures (building blocks 2, 3, and 4) as components of the "best system of emission reduction … adequately demonstrated." However, other stakeholders have disagreed that this approach is consistent with CAA section 111(d). According to these latter stakeholders, as a legal matter, the BSER is limited to measures that may be undertaken at the affected electric generating units (EGUs), including on-site controls, activities, or work practices, and cannot include measures that are beyond the affected units. These stakeholders take the position that although efficiency improvements at the affected EGUs may be included in the BSER,the measures in building blocks 2, 3, and 4 are "beyond-the-unit" measures because they are

implemented outside of the affected EGUs and outside of the control of their owners or operators.[61] Some stakeholders have also argued that section 111(d)(1) requires that the performance standards established by the states must reflect what is achievable at each existing unit.[62]

As the preamble notes, we welcome comment on these issues. As discussed above, we propose that the provisions of section 111 allow the BSER to include those types of

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[61] "Response of the Utility Air Regulatory Group to EPA's 'Considerations in the Design of a Program to Reduce Carbon Pollution from Existing Power Plants" (Oct. 2013); "Existing Source Performance Standards for Greenhouse Gas Emissions from Electrical Generating Units: Creating a Regulatory Framework Under Clean Air Act section 111(d) – A whitepaper from the Coalition for Innovative Climate Solutions" (Feb. 26, 2014); "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under §111(d) of the Clean Air Act," included in "Testimony before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce – 'EPA's Proposed GHG Standards for New Power Plants and H.R. __, Whitfield-Manchin Legislation'" (Nov. 14, 2013) (statement of E. Scott Pruitt), http://democrats.energycommerce.house.gov/sites/default/files/documents/Testimony-Pruitt-EP-EPA-GHG-Standards-Whitfield-Manchin-Legislation-2013-11-14.pdf. *See* National Climate Coalition, "Discussion Background Paper: Best System of Emission Reduction" (Oct. 16, 2013)("BSER approach that mandates reductions based on actions outside the control of the regulated source would involve legal uncertainty. There is nothing in the CAA that authorizes EPA to issue guidelines that require a standard to be based on something that is outside the fence and outside the control of the source.")

[62] "Response of the Utility Air Regulatory Group to EPA's 'Considerations in the Design of a Program to Reduce Carbon Pollution from Existing Power Plants" (Oct. 2013).

measures. In addition, as discussed above, under our proposed approach, affected sources may themselves implement the measures included in building blocks 2, 3, and 4, so that those measures are within their control. Moreover, under our proposed alternative approach, the "system of emission reduction" includes reductions in utilization at the affected sources themselves.[63] It

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[63] Commenters have critiqued this "at-the-unit" and beyond-the-unit" distinction as follows:

> There is an argument that the at-the-unit/beyond-the-unit distinction is not a meaningful one. Specifically, it could be argued that the distinction between at-the-unit and beyond-the-unit measures is largely artificial, because all of the emission reductions under consideration—whether from at-the-unit measures (e.g., fuel-switching or efficiency upgrades) or from beyond-the-unit measures—are, in fact, emission reductions at or from electric generating units on the interconnected electric grid. For example, neither the addition of renewable generation nor the reduction of end-user demand directly reduces atmospheric emission of CO2; rather these measures permit fossil EGUs to reduce their own output and emissions. It can be argued that all of the systems of emission reduction here contemplated—whether they involve end-use energy efficiency, displacing high-emission generation with lower emission generation, fuel-switching, heat-rate improvements, etc.—are effectively at-the-unit measures that ultimately reduce emissions solely from regulated EGUs. If energy-efficiency programs, added renewable energy, and redispatch from higher emitting facilities to lower emitting facilities are viewed as at-the-unit systems of emission reduction, the at-the-unit/beyond-the-unit distinction arguably becomes irrelevant—at least from a legal perspective.

should also be noted that, as discussed above, the re-dispatch measures in building block 2 are limited to affected sources. In addition, we discuss below that the performance standards that the states may establish under our approach meet the requirements of section 111(d)(1) and section 111(a)(1) because they would reflect the degree of the required emission performance level (which, in turn, is based on the BSER, as the EPA has applied it to the state's sources) that the state assigns to the affected EGUs. Thus, the proposed approach and alternative described next respond to these stakeholder concerns.

4. Second approach: Heat rate improvement measures inbuilding block 1 plus reduced utilization at levels commensurate with building blocks 2, 3 and 4

The EPA is also proposing an alternative approach to the BSER: heat rate improvements (building block 1) combined with reduced utilization in specified amounts of the affected fossil fuel-fired EGUs, commensurate with the amount of low- and zero-emitting generation and avoided generation in building blocks 2, 3, and 4. The reasons why

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Nordhaus R., Gutherz I., "Regulation of CO_2 Emissions from Existing Power Plants Under section 111(d) of the Clean Air Act: Program Design and Statutory Authority," *Environmental Law Reporter,* 44: 10366, 10383 n. 133 (May 2014).

the measures in building block 1 qualify as a component of this approach to BSER, and the reasons why the combination of building block 1 with the reduced generation qualify as the BSER are the same as discussed above in connection with the first approach to BSER and in the preamble, and will not be discussed further in this subsection 4. Instead, this subsection will discuss the reduced generation component of this second approach to BSER.

Under this approach, the measures in building blocks 2, 3, and 4 would not be components of the system of emission reduction but instead would serve as bases for quantifying the reduced generation (and therefore emissions) at affected EGUs, and assuring that the amount of reduced generation meets the criteria for the “best” system that is “adequately demonstrated” because, among other things, the reduced generation can be achieved while the demand for electricity services can continue to be met in a reliable and affordable manner. Specifically, the amount of generation from the increased utilization of NGCC units would determine a portion of the amount of the generation reduction component of the BSER for affected fossil fuel-fired steam EGUs; and the amount of generation from the use of expanded low- and zero-carbon generating capacity that could be provided, along with the amount of

generation from fossil fuel-fired EGUs that could be avoided through the promotion of demand-side energy efficiency, would determine a portion of the amount of the generation reduction component of the BSER for all affected EGUs.

For the reasons discussed below, reduced generation in the specified amounts is a "system of emission reduction," and meets the criteria to qualify as the "best" that is "adequately demonstrated."

a. "System of emission reduction"

Reduced generation is encompassed by the terms of the phrase "system of emission reduction" in CAA section 111(a)(1), as a matter of *Chevron* step 1, because, in accordance with the above-discussed definition of "system," reduced generation is a "set of things" – which include reduced use of generating equipment and therefore reduced fuel input – that the affected source may take to reduce its CO_2 emissions.

If the phrase "system of emission reduction" is not considered clear by its terms, then it may reasonably be interpreted under *Chevron* step 2 to include reduced generation, for several reasons. First, Congress has recognized reduced utilization in several contexts as a method to reduce air pollution. Beginning with the 1970

CAA Amendments, Congress has recognized that SIPs under CAA section 110, in order to assure reductions in NAAQS pollutants to meet attainment requirements, may need to impose emission limits on industrial sources that those sources could meet only by retiring.[64] Similarly, in adopting CAA section 112, which directed the EPA to promulgate emission standards for sources of hazardous air pollutants to a level of stringency that provides an "ample margin of safety to protect the public health,"[65] Congress was clear that the standards could be sufficiently stringent so that "effectively, … a plant would be required

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[64] *See* CAA section 110(g) (authorizing temporary emergency suspensions of SIP revisions if needed to prevent the closing of a source of air pollution), enacted as CAA section 110(f) in the 1970 CAA Amendments; 116 Cong. Rec. 42384 (Dec. 18, 1970), *reprinted in* 1970 Legislative History, vol. 1, at 132-33 (statement of Sen. Muskie) (discussing criteria for sources to receive compliance date extensions). Similarly, Congress recognized that to achieve the NAAQS, it was necessary to reduce emissions from motor vehicles, and that an important method of doing so could be restricting the use of motor vehicles in urban areas that were already highly polluted. For this reason, Congress included in the 1970 CAA Amendments authorization for SIPs under section 110 to include "transportation controls." CAA section 110(a)(2)(B), as approved in the 1970 CAA Amendments. Sen. Edmund S. Muskie (D-ME), who led the proponents for the Amendments in the Senate, explained that for some areas to attain the NAAQS, "[c]entral city use of motor vehicles may have to be restricted." 116 Cong. Rec. 42384 (Dec. 18, 1970), *reprinted in* 1970 Legislative History, vol. 1, at 132 (statement of Sen. Muskie).

[65] CAA section 112(b)(1)(B), as enacted in the 1970 CAA Amendments.

to close because of the absence of control techniques."[66] Congress's recognition that closing plants is a method of reducing pollution necessarily encompasses reduced utilization as a system of reducing pollution. As a result, it is reasonable to interpret the term "system of emission reduction," which Congress mandated as the basis for controls on section 111(d) air pollutants, to include reduced production.

Other examples of reduced utilization as a means of reducing emissions to comply with CAA requirements are found in settlement agreements between the EPA and fossil fuel-fired EGUs to resolve alleged violations of the CAA new source review (NSR) requirements. These agreements typically allow the EGUs to choose one of several means to comply with their emission reduction obligations, including retiring units.[67]

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[66] 116 Cong. Rec. 42385 (Dec. 18, 1970), *reprinted in* 1970 Legislative History, vol. 1, at 133 (statement of Sen. Muskie). Sen. Muskie added that the emission standards set by the EPA "could include emission standards which allowed for no measureable emissions," *id.,* which further suggests that, as a practical matter, the standards could result in reduced production.

[67] *See, e.g.,* Consent Decree, *USA v. Wisconsin Power and Light Co.,* Civil Action No. 13-cv-266 (WWi.DC), at 18, section IV, available at http://www2.epa.gov/sites/production/files/documents/wisconsinpower-cd.pdf

Reduction of, or limitation on, the amount of generation is already a well-established means of reducing emissions of pollutants in the electric sector, notwithstanding the fact that as a practical matter, some facilities may have to operate, or remain available, to ensure system reliability. For example, reduced generation by higher-emitting sources is one of the compliance options available to, and used by, EGUs to comply with the Clean Air Act acid rain program in CAA title IV, as well as the transport rules that we refer to as the NOx SIP Call[68] and the Clean Air Interstate Rule (CAIR).[69] Reduction in generation is also a possible means by which an EGU can achieve compliance with its requirements under RGGI.

b. "Best system of emission reduction … adequately demonstrated"

Reduced generation in specified amounts meets the criteria to be the "best" system of emission reduction that is "adequately demonstrated." Reduced generation is technically feasible due to the source's ability to limit its own operations. Moreover, because the amount of reduced generation may be substituted with the building block 2, 3, and 4 measures for increased generation from low- or zero-

[68] 63 FR 57356 (Oct. 27, 1998).
[69] 70 FR 25162 (May 12, 2005).

emitting sources and increased demand-side energy efficiency, that amount may be determined with precision and may be accomplished in a manner that assures the reliability of the electricity grid.

Specifically, through this reduced generation approach, the amount of emission reduction achieved is appropriate, as discussed above. In addition, the cost of the levels of reduced generation are reasonable for the affected source category and the nation-wide electricity system and do not jeopardize reliability. This is because the measures in building blocks 2, 3, and 4 are already in widespread use in the industry, and it is reasonable to expect that these measures will develop to achieve the levels proposed as part of this approach and thereby ensure an adequate and reliable supply of electricity. Moreover, reduced generation from fossil fuel-fired EGUs and its replacement through the measures in building blocks 2, 3, and 4 is consistent with trends in the energy sector and offer promise to reduce the carbon intensity of the system over the near- and long-term. This approach also promotes the development and implementation of technologies that are important for continued emissions reductions by increasing the demand for those technologies. This is because of the interconnected nature of the electrical grid and the

fungibility of electricity, which allows decreases in utilization at one facility to be seamlessly offset by increased utilization elsewhere (building blocks 2 and 3) or by decreased demand (building block 4), and thereby makes reduced utilization a viable approach for emissions reductions by EGUs. Further, this fungibility increases over longer timeframes with the opportunity to invest in infrastructure improvements, and as noted elsewhere, this proposal provides an extended state plan and source compliance horizon. Thus, this approach is consistent with the case law, which authorizes the EPA to determine the BSER by "balanc[ing] long-term national and regional impacts," and by "using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems…."[70]

Reduced generation in those amounts is also "adequately demonstrated." As noted above and discussed further in the preamble, the measures in building blocks 2, 3, and 4 are already in widespread use in the industry. At the levels proposed, they have the technical capability to substitute for reduced generation at some or all affected EGUs at reasonable cost. The NGCC capacity necessary to

[70] *Sierra Club v. Costle*, 657 F.2d 298, 331 (D.C. Cir. 1981).

accomplish the levels of generation reduction proposed for building block 2 is already in operation or under construction. Moreover, it is reasonable to expect that the incremental resources reflected in building blocks 3 and 4 will develop at the levels requisite to ensure an adequate and reliable supply of electricity at the same time that affected EGUs may choose or be required to reduce their CO_2 emissions by means of reducing their utilization. There are several reasons for this. First, the affected sources themselves could invest in new renewable energy resources and demand-side energy efficiency, as discussed in the preamble.[71] Second, the states, as part of their plans, have mechanisms available to put these substitutes in place: they could establish requirements or incentives that would result in new renewable energy and demand-side energy efficiency programs, as also discussed in the preamble.[72]

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[71]It should be noted that in light of the low current and projected near term prices for natural gas, market forces may lead investors to choose to build new NGCC units, rather than new renewable resources. This result would not call into question the technical feasibility of a BSER that included reductions in fossil fuel-fired generation by the amount of a specified amount of new renewable resources. This is because under these circumstances, the fossil fuel-fired generators could still reduce their generation without causing reliability or other problems in the electric power system.

[72] The nuclear generating capacity reflected in building block 3 is already in operation or under construction.

Third, as also discussed in the preamble, regional entities in the electricity system can accommodate these substitutes.

Most broadly, with respect to the measures in building blocks 2, 3, and 4, provided there is sufficient lead time for planning, mechanisms are in place in both regulated and deregulated electricity markets to assure that substitute generation will become available and/or steps to reduce demand will be taken to compensate for reduced generation by affected EGUs. These mechanisms are based on, among other things, the integrated nature of the electricity system coupled with the availability of capacity in existing NGCC units, the growing institutional capacity of entities that develop renewable energy and demand-side energy efficiency resources, and the ability of system operators and state regulators to incentivize further development of those resources.

7. Re-dispatch and sources in the regulated source categories.

As described in the preamble, building block 2 consists of reductions in generation from fossil fuel-fired steam generating units, and corresponding increases in generation by NGCC units. The amount of this re-dispatch is the amount that the steam generating units may reduce, and

that NGCC units may increase, up to an average of 70% capacity utilization of the NGCC units.

Accordingly, this component of the BSER involves two sets of affected sources. The first (the steam generating units) decreases their emissions. The second (the lower-emitting NGCC units) may increase their emissions if increased operations are necessary to ensure the ongoing reliability of the integrated electricity system, of which both sets of source are a part, as emissions and generation reduction is occurring at steam generating units and net reductions are being achieved. Both these sets of sources are affected sources because they are in source categories that are covered by this rulemaking. As noted in the preamble, the fossil fuel-fired steam generating boilers are in a source category that the EPA listed under CAA section 111(b) in 1971, and the NGCC units are in a source category that EPA listed in 1979. The NGCC units (as well as the steam-generating units) are subject to reduction requirements through other components of the BSER, specifically, building blocks 3 and 4 (low- and zero-emitting energy and demand-side energy efficiency, respectively). In addition, as noted in the preamble, the EPA is co-proposing to combine the two source categories

into a single source category, covering fossil fuel-fired EGUs.

8. Building blocks 2, 3, and 4: intra-state and inter-state compliance

In this section, we discuss the issue of whether CAA section 111(d) limits the EPA to applying the re-dispatch component (building block 2) of the BSER, based on the assumption that each state will comply with that component on a purely intra-state basis, or instead, whether the EPA could base building block 2 on an assumption that the states will comply with that component through the interstate region with which they share the grid.

As the preamble describes, in evaluating building block 2, we have assumed that each state would implement it on a state-by-state basis, without relying on a multi-state regional grid. In particular, we have assumed that each state would increase generation of its own NGCC units to as close to the proposed average 70% capacity utilization as possible, given the amount of generation from in-state fossil fuel-fired steam generating units, and we assumed the corresponding amount of reduction in generation from those steam generators. We have determined the costs of that re-dispatch, and propose to find that they are

reasonable.[73] Because we know that dispatch systems operate over multi-state regions, however, we have also determined the costs of the re-dispatch if each state that is part of a multi-state grid implements re-dispatch by taking into account the multi-state grid in which it operates.

We found that based on the intra-state approach, some states could not increase their average NGCC unit utilization to 70% because they have limited fossil fuel-fired steam generation. In contrast, based on the region-wide approach, more of the states could increase their average NGCC utilization to 70%. In addition, the costs of the intra-state approach are demonstrably higher than the costs of the region-wide approach. In fact, we expect that because all of the lower-48 states, with the exception of Texas, are part of a multi-state, regional grid each state's implementation of building block 2 would, as a practical matter, necessarily occur on an interstate, and not an intrastate, basis.

CAA section 111(d)(1), by its terms, applies requirements on a state-by-state basis. It requires that "each State shall submit to the Administrator a plan" that includes standards of performance as well as implementing

[73] It should be noted that we also evaluated region-wide re-dispatch, for which the costs are less.

and enforcing measures. Further, it allows "the State in applying a standard of performance to any particular source under a [state] plan" to take into consideration factors such as the source's remaining useful life.

These provisions raise the issue of whether section 111(d) may be interpreted so that the re-dispatch component of the BSER may be applied on the assumption that each state would implement that component on a purely intra-state basis, or whether section 111(d) may be interpreted so that the re-dispatch component may be applied on the assumption that each state would implement through the operation of the interstate grid in which it participates. This issue may also apply to building blocks 3 and 4.

C. Application of the BSER; achievability of the emissions standards

1. Introduction and Overview

In this subsection C, we discuss our interpretation of the CAA sections 111(d)(1) and 111(a)(1) requirements that each state must develop a plan that establishes for "any existing source"[74] "standards of performance," which are

[74] It should be recalled that although in this subsection C. we refer to "any existing source" or "each existing source" in the state, or we use similar terms, CAA section 111(d) applies to only those existing sources that would be covered by a section 111(b) standard if they were newly constructed or if they modified or reconstructed.

defined as emission standards that "reflect the degree of limitation achievable through the application of the best system of emission reduction ... adequately demonstrated." We explain why our state-wide approach to applying the BSER and the emission standards that result from the state plan process we require are consistent with these section 111 provisions.

These provisions make clear that an important aspect of the state's establishment of the standards of performance is "the application of" the BSER. In this rulemaking, the EPA is proposing to apply the BSER for affected EGUs on a statewide basis. The statewide approach also underlies the required emission performance level, which is based on the application of the BSER to a state's affected EGUs, and which the suite of measures in the state plan, including the emission standards for the affected EGUs, must achieve overall. The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance -- and, for the portfolio approach, in imposing requirements on other entities -- as long as, again, the required emission performance level is met.

This state-wide approach both harnesses the efficiencies of emission reduction opportunities in the interconnected electricity system and is fully consistent with the principles of federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly. That is, section 111(d) achieves the emission performance requirements through the vehicle of a state plan, and provides each state significant flexibility to take local circumstances and state policy goals into account in determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements.

For convenience, we set out the requirements of CAA sections 111(d)(1) and 111(a)(1) here: under CAA section 111(d)(1), the state must adopt a plan that "establishes standards of performance for any existing source." Under CAA section 111(a)(1), a "standard of performance" is a "standard for emissions … which reflects the degree of emission limitation achievable through the application of the best system of emission reduction … adequately demonstrated." The EPA proposes to interpret these provisions as set forth in this sub-section.

The first step is for the EPA to determine the "best system of emission reduction … adequately demonstrated." As discussed at length elsewhere, the EPA is proposing two alternative BSER. The first is the measures in building blocks 1 through 4 combined. This includes operational improvements and equipment upgrades that the coal-fired steam-generating EGUs in the state may undertake to improve their heat rate by, on average, six percent and increases in, or retention of, zero- or low-emitting generation, as well as measures to reduce demand for generation, all of which, taken together, displace, or avoid the need for, generation from the affected EGUs. This BSER is a set of measures that impacts affected EGUs as a group. The alternative approach to BSER is building block 1 combined with reduced utilization from the affected EGUs in the state as a group, in the amounts that can be replaced by an increase in, or retention of, zero- or low-emitting generation, as well as reduced demand for generation.

After determining the BSER, the EPA then applies the BSER to each state's affected EGUs, on a state-wide basis. Building block 1 is applied to the coal-fired steam-generating EGUs on a statewide basis; building block 2 is applied to increase the generation of the NGCC units in the state up to certain amounts, and decrease the amount of

generation from steam-generating units accordingly; and the measures in building blocks 3 and 4 are applied to reduce, or avoid, generation from affected EGUs on a state-wide basis. Under the alternative formulation of the BSER, the total amount of reduced generation from the affected EGUs in the state, associated with the measures in building blocks 2, 3, and 4, is determined on the basis of each state's affected EGUs as a group.

This statewide approach to applying the BSER is consistent with the CAA section 111(a)(1) definition of "standard of performance," which, as quoted above, refers to "the application of the [BSER]," for the purpose of determining "the degree of emission limitation achievable," but does not otherwise constrain how the BSER is to be applied. As a result, we, as the administering agency, have discretion under Chevron step 2 to fashion an interpretation that is a reasonable construction of the CAA provisions.[75] Similarly, the implementing regulations give the EPA broad discretion to identify the group of sources to which the BSER is applied. The regulations provide that the EPA "will specify different emission guidelines or compliance times or both for different sizes, types, and

[75] *Chevron U.S.A. Inc. v. NRDC*, 467 U.S. 837, 842-844 (1984).

classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate."

In this rulemaking, the EPA is applying the BSER to the affected EGUs in each state as a group. As we have noted, for this industry, a state-wide approach harnesses the efficiencies of emission reduction opportunities in the interconnected electricity system, including the opportunities to reduce emissions from all affected EGUs through reasonable cost, lower-emitting replacement generation. Accordingly, under the implementing regulations just quoted, it is "appropriate" to apply the BSER to the affected EGUs in each state as a group.

As part of applying the BSER, the EPA, to return to provisions of CAA section 111(a)(1), calculates the "emission limitation achievable through the application of the [BSER]." In this rulemaking, we refer to this amount as the state goal. As noted, the EPA expresses the state goal in the emission guidelines as an emission rate.

The state must develop a state plan that achieves the state goal, either in the form of an emission rate, as specified for the state in the emission guidelines, or a translated mass-based version of the rate-based goal. We refer to the state goal, in the form used by the state as

the foundation of its plan, as the required emission performance level.

As part of its state plan, the state must establish "standards of performance" for its affected EGUs. To do so, the state may consider the measures the EPA identified as part of the BSER or other measures that reduce emissions from the affected EGUs. Moreover, the state has the flexibility to establish emission standards in the degree of stringency that the state considers appropriate.[76] The primary limitation on the state's flexibility is that the emissions standards applied to all of the state's affected EGUs -- and, in the case of states that adopt the portfolio approach, the requirements imposed on other affected entities -- taken as a whole, must be demonstrated to achieve the required emission performance level. In addition, the state may make the emission standards for any of its affected EGUs sufficiently stringent, so that the standards and any requirements imposed on other affected

[76] Looked at another way, through our proposal, consistent with the EPA's authority in determining the BSER to subcategorize sources on the basis of costs and other factors, *see* 40 CFR 60.22(b)(5), the state has the opportunity in effect to subcategorize its sources on the basis of their costs and other considerations associated with their position in the interconnected electricity grid, and to assign responsibilities for achieving the emission performance level accordingly.

entities (if relevant), taken as a whole, achieve a level of emission performance that is better than the required emission performance level. See CAA section 116, 40 CFR 60.24(g).[77]

Under these circumstances – that the emission standards that the state establishes for its affected EGUs and any other requirements for the other affected entities, as relevant, taken together, are at least as stringent as necessary to achieve the required emission performance level for the state's affected EGUs - each emissions standard that the state adopts for each of its affected EGUs will meet the definition of a "standard of performance" under CAA section 111(a)(1). Specifically, the "standard of performance" for each source will constitute, to return to the provisions of CAA section 111(a)(1), "a standard for emissions which reflects [that is, embodies, or represents][78] the degree [that is, the portion] of emission limitation achievable through the application of

[77] By comparison to state implementation plans (SIPs) under CAA section 110, although section 111(d) state plans differ from SIPs in that the latter are designed to achieve a NAAQS, section 111(d) plans that are designed to achieve a required emission performance level incorporate many of the same flexibilities as SIPs.

[78] See Oxford Dictionary of English (3rd ed. 2010 (online version 2013)) (defining "reflect" as, among other things, "embody or represent (something) in a faithful or appropriate way").

the [BSER]" [that is, as noted above, the required emission performance level for all affected sources in a state]. That "degree" or portion of the required emission performance level is, in effect, the portion of the state's obligation to limit its affected sources' emissions that the state has assigned to each particular affected source. An emissions standard meets this definition of the term "standard of performance" regardless of whether it is part of a plan that adopts the portfolio approach (in which case, the standard will reflect a relatively smaller part of the emission performance level) or one that imposes the plan's emission limitation obligations entirely on the affected EGUs (in which case, the standard will reflect a relatively larger part of the emission performance level).[79]

[79] The EPA's approach may also be characterized as (i) determining the BSER for the affected EGUs, (ii) establishing as the emission guideline the standard for emissions that the affected EGUs in the state can achieve on average through the application of the BSER, and (iii) as part of the emission guideline, authorizing each state to establish as the applicable standard for each affected EGU, the standard that the state considers appropriate and that when totaled with the standards established for the other EGUs (and as may be adjusted to account for the portfolio approach, if that approach is adopted by the state) is at least as stringent as the average standard in the emission guideline. As noted in the accompanying text, a state has many ways to establish standards that meet the CAA requirements, including, for example, following the BSER or authorizing emission rate averaging or trading.

These proposed interpretations of the provisions of CAA sections 111(d)(1) and (a)(1) are fully consistent with the EPA's overall approach in this rulemaking to determining and applying the BSER and identifying the appropriate level of emission performance for the affected EGUs. As noted, this approach entails applying the BSER on a state-wide basis and, based on the BSER, identifying the emission performance level that each state must achieve, so that each state may then assign responsibilities for achieving that performance level among its sources. As noted, this approach is fully consistent with the interconnected nature of the electricity system and with the principles of federalism that form part of the foundation of the Clean Air Act, and that find expression in section 111(d) through its provisions implementing the required emission controls through the vehicle of state plans. We also note that, as part of our proposal for BSER, applying the "best system of emission reduction … adequately demonstrated" on a statewide basis in this manner is consistent with interpreting the term "best" to include those principles of federalism. That is, one reason why each of our proposed two alternative approaches for BSER qualifies as the "best" system is that, in effect, each can be implemented in an efficient manner by a state –

through its obligation to assure achievement of the emission performance level that is based on the BSER -- which may mean assigning greater responsibility for emission limitations to some affected EGUs than to others.

It should be emphasized that each state has many options for assigning the emission limitation obligations among its affected sources.[80] For example, the state could impose emission standards that directly flow from the BSER. Under these circumstances, the state may assign to different affected sources emission standards with different levels of stringency because the state will have determined that those standards are consistent with the extent to which the low- or zero-emitting generation in building blocks 2, 3, and 4 will displace the source's generation and thereby lower the source's emissions. The state may establish a relatively less stringent emission standard for a source that the state considers will not have much of its generation displaced than the state may for a source that the state considers will have more of its

[80] One of the advantages of the flexibility states have under the EPA's approach is that state officials may utilize their knowledge of the electricity sector in their state and of the entities involved in fashioning the standards of performance and other requirements.

generation displaced.[81] The state could base this approach on the recognition that the increased zero- and low-emitting generation displaces generation from affected sources in different amounts, depending on the affected sources' costs and on other factors, such as transmission line capacity.

In addition, the state could authorize emission trading as part of the emission standards for affected sources. Under these circumstances, if an affected source's emissions level was higher than the standard the state established for it, the source could achieve the standard by purchasing additional emission rights through the trading program.

It bears emphasis that each state has flexibility in establishing the standards of performance for its existing sources as long as, on a state-wide basis, those standards (and, in the case of the portfolio approach, any other permissible measures in the state plan) achieve the state's

[81] It should be noted that if the state wished to pattern the emissions standards after the way that the source was affected by the BSER, the state would also need to consider the extent to which the source can implement the heat rate improvements in building block 1, but for purposes of simplifying this example, we will set that consideration aside. It should also be noted that this example assumes that the state, in assigning emission rates to its sources, credits reductions in emissions due to reductions in generation against the emission rate.

required emission performance level. This flexibility is in keeping with the nature of the BSER that we have determined and the state-wide manner in which we have applied it to each state's existing sources. This flexibility is also consistent with the interconnected nature of the electricity system, through which the fossil fuel-fired EGUs are connected to, and affect, each other, and are all affected by other sources of generation.

Finally, it should be noted that states retain authority under CAA section 116 and 40 CFR 60.24(g) to impose standards of performance that, cumulatively, are more stringent than the emission performance level.

This is a preliminary, unedited transcript. The statements within may be inaccurate, incomplete, or misattributed to the speaker. A link to the final, official transcript will be posted on the Committee's website as soon as it is available.

RPTS ZAMORA

DCMN HERZFELD

EPA'S PROPOSED CARBON DIOXIDE

REGULATIONS FOR POWER PLANTS

THURSDAY, JUNE 19, 2014

House of Representatives,

Subcommittee on Energy and Power,

Committee on Energy and Commerce,

Washington, D.C.

The subcommittee met, pursuant to call, at 9:30 a.m., in Room 2123, Rayburn House Office Building, Hon. Ed Whitfield [chairman of the subcommittee] presiding.

Present: Representatives Whitfield, Shimkus, Pitts, Terry, Burgess, Latta, Cassidy, Olson, McKinley, Gardner, Pompeo, Kinzinger, Griffith, Barton, Upton (ex officio), Rush, McNerney, Tonko, Yarmuth,

Engel, Green, Capps, Doyle, Barrow, Matsui, Castor and Waxman (ex officio).

Staff Present: Nick Abraham, Legislative Clerk; Gary Andres, Staff Director; Charlotte Baker, Deputy Communications Director; Leighton Brown, Press Assistant; Allison Busbee, Policy Coordinator, Energy and Power; Annie Caputo, Professional Staff Member; Patrick Currier, Counsel, Energy and Power; Tom Hassenboehler, Chief Counsel, Energy and Power; Ben Lieberman, Counsel, Energy and Power; Brandon Mooney, Professional Staff Member; Mary Neumayr, Senior Energy Counsel; Graham Pittman, Staff Assistant; Peter Spencer, Professional Staff Member, Oversight; Tom Wilbur, Digital Media Advisor; Jean Woodrow, Director, Information Technology; Jeff Baran, Minority Staff Director, Energy and Environment; Phil Barnett, Minority Staff Director; Caitlin Haberman, Minority Policy Analyst; Bruce Ho, Minority Counsel; Elizabeth Letter, Minority Press Secretary; Karen Lightfoot, Minority Communications Director and Senior Policy Advisor; and Alexandra Teitz, Minority Chief Counsel, Environment and Energy.

regulations that have such an impact everywhere. And so I just wanted -- Dr. Schneider is not the only lead coordinator that has made these statements. Others have said we have to make them dramatic to put political pressure on political leaders. Others have said we use the worst-case model scenarios.

So, as I said in the beginning, our responsibility is try to focus in and see really what is going on here. And so the first question I would like to ask you this morning, I touched on it in my opening statement, EPA's carbon dioxide regulations for power plants are being pursued under section 111(d), and it is my understanding that you-all issued regulations under that section on five occasions. And now section 111(d) has traditionally focused, and, in fact, of those five times it has always focused, on emissions standards for specific sources, specific units, and it has never been attempted to do it in a statewide way, and that is what your recent proposal does. It sets a standard that can be achieved only statewide.

What precedent under section 111(d) is there for this type of standard setting which has never been done before?

Ms. McCabe. There actually have been six regulations issued under 111(d), the last one being the clean air mercury rule in 2005, which addressed this sector, and that took an approach that allowed utilities to trade among themselves to reduce emissions. But the fact

is that what we have done in this rule is completely within the four corners of 111(d), which directs us to identify the best system of emission reduction that has been adequately demonstrated for the particular sector that we are looking at. And in the case of the power sector, it is a fully integrated system that encompasses the kinds of technologies that we included in the rule, and we know that because that is what we heard from States and utilities. These are the things they are already doing to reduce carbon from fossil power plants.

Mr. Whitfield. But, you know, in this rule, you, for the first time -- I mean, you basically are directing the States on setting up renewable mandates. You are setting the efficiency of the coal plants. You are determining the natural gas capacity, what percent of the capacity must be run. You are setting consumer demand. You are going further than you have ever done before, in my opinion.

Ms. McCabe. We are not actually setting any mandates in the rule.

Mr. Whitfield. But you set this out in the regulation.

Ms. McCabe. But they are not mandates. The States have absolute flexibility to use whatever method --

Mr. Whitfield. They -- don't they have to meet those four standards?

Ms. McCabe. They do not have to meet those four standards. Those were the --

Mr. Whitfield. You have to meet -- they have to meet your target, though.

Ms. McCabe. They have to meet the overall carbon intensity target, but they have complete flexibility to get there however they choose, which is what they told they wanted.

Mr. Whitfield. We are going to explore it some more, but I have 15 seconds left. I want to ask one other questions. One of the real concerns we have -- now, this relates to the new power plant rule. We can't build a new plant in America because the technology is not there that commercially makes it feasible. The Kemper plant in Mississippi is like a 5 billion cost overrun. In Europe, they are closing down natural gas plants. They are mothballing them because natural gas prices are so high coming out of Russia, so they are building new coal-powered plants, and last year they imported 53 percent of our coal exports.

So they have the flexibility, if gas prices go up, to build a new plant. We don't have that flexibility. Do you think that that is fair to the American people?

Ms. McCabe. I actually disagree respectfully, Chairman. We think that new coal plants can be built under the new rule, and they are going forward.

Mr. Whitfield. At this time I would like to recognize the

gentleman from Illinois Mr. Rush for his 5-minute opening statement.

Mr. Rush. Thank you, Mr. Chairman. I want to commend Ms. McCabe, I want to commend the EPA, I want to commend all your colleagues for the way you have approached this proposal. I think that you have been extremely open during this process of creating this proposal, and from what I hear today, that this process has not concluded, that there will be more and more opportunities for States and stakeholders to add their voices and to look at this proposal and to engage in positive commentaries with you on this proposal. You already reached out and asked for suggestions and been guided by that feedback.

I am from the Midwest, and we get a lot of our electricity from coal. We have a higher climate pollution, rates are -- at the beginning, starting out at the gate, but also means that we have more opportunities for cost-effective reductions.

And I want you, if you would, explain to me and to others in more detail how you develop the States' loans, particularly for the Midwest, and how the different situations and the different States are reflected in the individual State loans.

Ms. McCabe. That is a very good question, Congressman Rush, and one that we have been getting a lot from people, and it really goes back to the fundamental approach that we took in this rule, which is to take every State from where it started. One of the loudest things

that we heard from States was please don't do a one-size-fits-all, every plant across the country has to meet a certain emission limit. Give us flexibility and recognize that States are in different places in terms of their energy mix, the age of their plants, and all that sort of thing. So that is the approach that we took.

We looked across the whole country at the power sector, and we looked at the things that people were already doing, and there are many things that can be done to reduce carbon from the existing fleet, but we found four that were the most prominent and the most promising, we thought, to satisfy the standard of best system of emission reduction. And those things are let's have the coal and gas plants be as absolutely efficient as they can be so that we get every -- we get every electron, as many electrons as possible for every ton of coal that is burned, and we found that a lot of efficiency improvements are being made across the country.

We then looked at what else are States and utilities doing to reduce their carbon intensity. Well, they are using their gas plants more than their coal plants, and that is due to a lot of reasons, but it results in less carbon, so that was number two.

Number three was that States all across the country are looking at increasing the amount of energy they get from renewable sources, from zero-carbon-emitting sources, and that is a very positive trend

being pursued by a lot of people. So that was our third element.

And fourth was the great interest across the country, in almost every State, to employ energy efficiency or demand sites so that we are more efficient. We know there is many, many ways to waste less energy, and all of these things are important in order to bring carbon down, as well as other pollutants.

So we came up with a national framework that set a reasonable and moderate expectation for each of those four, recognizing that those were not the only things that States could do. And we then looked at every State, and we took the most recent information that we had for the power sector, which was 2012, and we applied those four building blocks, we call them, to each State, and that generated a carbon intensity rate that, if those were applied, that is where that State would get. And these are things that we think are very reasonable to achieve.

Mr. Rush. Thank you. Thank you very much.

My constituents, when they heard about this proposed rule, the thing that was most important in their mind was the price of electricity. My friends on the other side here, they have been engaged in a lot of fear mongering about the cost of electricity is going to increase and be unaffordable by low-income constituents. And my question to you is how will the Clean Power Plan affect the electricity

bills for my constituents?

Ms. McCabe. Well, the first and most important thing to say is that each State will be in charge of designing its own plan, so that means two things. One is that they will have the opportunity to take those kind of considerations into -- build those into their plan, but also that EPA at this moment can't predict exactly what every State is going to do.

We did do some illustrative examples of what States might do, and so in our regulatory impact assessment, we do include those numbers, and that we show that with the significant increase in energy efficiency that will be implemented as a result of the rule, that electricity bills in 2030, we predict, will go down because -- electricity bills -- because people will be using less energy. We also show that the price of electricity will go up a little bit, but overall, bills will come down.

I also just want to note that low-income families are most at risk of the adverse effects of carbon pollution and climate change and can greatly -- will greatly benefit from the health benefits that will be achieved by this rule.

Mr. Whitfield. Gentleman's time is expired.

Mr. Rush. Thank you, Mr. Chairman.

Mr. Whitfield. At this time I recognize the chairman of the full

committee, Mr. Upton of Michigan, for 5 minutes.

The Chairman. Thank you, Mr. Chairman.

Ms. McCabe, I believe a number of us have concerns with this proposed rule. EPA, an Agency with no energy policy authority or expertise, and under questionable statutory interpretation, has now placed itself above State governments and public utility commissions on electric-generation issues, not to mention, DOE, FERC, or other Federal agencies. Last month the D.C. circuit ruled that absent, and I quote, "clear and specific grant of jurisdiction," end quote, the Federal Government cannot regulate areas of the electricity market left by the Federal Power Act to the States, like electricity generation and intrastate transmission. But what EPA calls flexibilities in its proposed reg, changing dispatch rules, mandating efficiency, utilizing other generation sources, are, in fact, the very intrastate generation transmission and distribution matters explicitly reserved by the Federal Power Act for the States.

So where do you see specifically the clear and specific grant of jurisdiction over intrastate electricity matters? Where is the cite that you can refer to.

Ms. McCabe. Chairman Upton, this is not an energy plan. This is a rule done within the four corners of 111(d) that looks to the best system of emission reduction to reduce emission. No State is required

to enter into any particular agreement or take interstate efforts. We are not controlling the power sectors through this.

The Chairman. So you don't have a specific cite, right? Is that right?

Ms. McCabe. I can --

The Chairman. Because neither DOE nor FERC has the authority to dictate how States plan and operate their energy systems, so if they can't do it, what authority does EPA have to mandate that the States actually restructure their electric systems and subject State energy decisions to Federal oversight and control?

Ms. McCabe. That is not what the rule does. The rule is a pollution control rule, as EPA has traditionally done under section 111(d).

The Chairman. Well, assuming that you had the legal authority to go forward with the rule, have you identified all the Federal and State agencies that would have to play a role in the redesign of the State electricity systems under the proposed rule?

Ms. McCabe. We have been talking to many agencies at State and Federal level, but it is State governments, as they always are with respect to 111(d) plans, that will be responsible for putting these plans together.

The Chairman. So, as we look in EPA's budget, and this year EPA

took a reduction in appropriation levels, an agreed-upon amount in a bipartisan way, from the CR that was passed 6 to 1 last January, have you identified more funding of personnel that is going to be required at the Federal level to conduct this review and oversight for existing plants?

Ms. McCabe. These are State plans. The States will put them together, and EPA will act in its traditional role with respect to State air quality planning.

The Chairman. But you still got -- you know, you have got the hammer to go after them, so are you -- is it going to be a new -- new folks engaged in that?

Ms. McCabe. We think States will want to take a leadership role on this and --

The Chairman. What if they don't? I heard the West Virginia Governor saying that every utility in his State would be closed. Every coal-fired facility in his State was going to be closed.

Ms. McCabe. Again, I think that States are going to want to be in the lead on this plan.

The Chairman. I think I know where they want to be.

Ms. McCabe. I also would suggest that our plan certainly does not require that all coal plants be closed in that State or any State.

The Chairman. Well, I will leave that for Mr. McKinley to ask.

BY EMAIL AND ELECTRONIC FILING

The Hon. Gina McCarthy
Administrator, U.S. Environmental Protection Agency
EPA Docket Center
Mail Code 28221T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Attn: Docket ID No. EPA-HQ-OAR-2013-0602

Re: Comments of Environmental Defense Fund on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34, 830 (June 18, 2014); 79 Fed. Reg. 64,543 (Oct. 30, 2014) (Notice of data availability); 79 Fed. Reg. 67,406 (Nov. 13, 2014) (Notice; additional information regarding the translation of emission rate-based CO2 goals to mass-based equivalents)

The Environmental Defense Fund (EDF) appreciates the opportunity to provide the following comments on the Environmental Protection Agency's (EPA) June 18, 2014 proposed rule to establish performance standards for carbon pollution from existing electric utility generating units (EGUs).[1] Representing over 750,000 members nationwide, EDF is a national non-profit, non-partisan organization dedicated to protecting human health and the environment by effectively applying science, economics, and the law. EDF has long recognized the urgent and critical threat that climate change poses to public health and welfare, and it is one of our top priorities to advocate for rigorous measures to secure rapid reductions in emissions of climate-destabilizing pollutants – especially emissions of carbon dioxide from fossil fuel-fired EGUs, which currently account for nearly 40 percent of the United States' carbon pollution. Accordingly, we strongly support EPA's initiative to establish the first nation-wide limits on carbon pollution from fossil fuel-fired EGUs using its existing authorities under section 111(b) and (d) of the Clean Air Act.[2]

EPA's proposed rule for existing EGUs is a vital part of this initiative. Our comments below are directed at ensuring that these pollution standards meet the Clean Air Act's standard—that they deliver the maximum possible emission reductions considering cost and the other statutory factors—and are

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (proposed June 18, 2014).
[2] 42 U.S.C. § 7411(b), (d).

coordinated effectively with EPA's standards for newly constructed, modified, and reconstructed fossil fuel-fired EGUs.

All prior written and oral testimony and submissions to the Agency in this matter, including all citations and attachments, as well as all of the documents cited to in these comments and attached hereto are hereby incorporated by reference as part of the administrative record in this EPA action, Docket ID No. EPA–HQ–OAR–2013–0602.

We appreciate the opportunity to provide comments on this important rulemaking. Please direct any inquiries regarding these comments to Megan Ceronsky, Director of Regulatory Policy and Senior Attorney at EDF, or Tomás Carbonell, Senior Attorney at EDF.

Respectfully submitted,

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Attachments:

Attachment A: John A. "Skip" Laitner & Matthew T. McDonnell, *Energy Efficiency as a Pollution Control Technology and a Net Job Creator Under Section 111(d) Carbon Pollution Standards for Existing Power Plants* (Nov. 28, 2014)

Attachment B: Brief Amicus Curiae of Electrical Engineers, Energy Economists and Physicists in Support of Respondents in No. 00-568, *New York v. FERC*, 535 U.S. 1 (2002)

Attachment C: Andover Technology Partners, *Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers* (Nov. 30, 2014)

TABLE OF CONTENTS

Executive Summary

EDF strongly supports EPA's proposed Clean Power Plan. In these comments we discuss the urgency of acting to address carbon pollution from the largest source in our country and lay out the strong legal foundation upon which the Clean Power Plan is based. We strongly support EPA's approach to identifying the "best system of emission reduction" to address carbon pollution from power plants; EPA's approach fulfills the statutory requirements and appropriately reflects the uniquely unified and interconnected nature of the electric grid and the generation resources that energize it as well as the end-users who use power from it. We describe the consistency of this rulemaking with past federal clean air standards addressing power plant emissions and the distinct roles of the Federal Energy Regulatory Commission and public utility regulators in regulating aspects of the power sector, roles they will play in the context of these standards and have played in the context of all prior power plant emission standards. We explore the conflict between the 1990 House and the Senate amendments to Section 111(d) and EPA's clear authority to address carbon pollution from power plants in that context. We discuss the key role that environmental justice must play in EPA's mission and how environmental justice concerns should be addressed in the context of the Clean Power Plan.

We then examine the technical foundation for EPA's four building blocks, and recommend changes to the proposal that would more accurately reflect the potential to reduce carbon pollution from regulated fossil fuel-fired plants and drive greater pollution reductions. Finally, we recommend adjustments to address the potential for emission "leakage" across state lines, discuss the importance of ensuring that the Act's requirement for enforceability is met through federally enforceable plan components and standards or "backstops" enforceable against regulated sources that ensure state targets are attained, and explain the irreducible components of a state submittal requesting a delay in the deadline for state plan submission.

In summary, the comments make the following recommendations:

A. Summary

We strongly support EPA in moving forward with the proposed Clean Power Plan in a strengthened form. We strongly support EPA's proposed "best system of emission reduction", which looks at the real-world potential to reduce carbon pollution by deploying renewable energy, harvesting our nation's vast energy efficiency resource, improving the efficiency of power plants, and relying more on lower-emitting power plants and less on the highest-emitting power plants. We urge EPA to finalize these historic and urgently needed carbon pollution standards by June 1, 2015, as set forth in the Presidential Memorandum on Power Sector Carbon Pollution Standards.

We also urge EPA to strengthen the environmental benefits of the standards by:

- Recognizing the full potential across the electric system and all resource types to reduce emissions and especially utilizing updated cost and performance data for renewables and energy efficiency to ensure we achieve more at lower cost;

- Strengthening the emissions outcome in 2020 – near term emissions reductions are vital for climate security; and

- Significantly strengthening the emissions outcome in the later years – 2030 is far too long to achieve such modest emission reductions.

B. Background

It is imperative that we dramatically reduce carbon pollution. The science is clear: rising concentrations of heat-trapping gases like carbon dioxide in the atmosphere will destabilize our climate and lead to severe impacts on our health and well-being and risk triggering catastrophic climate change.

We are already seeing the impacts of climate change on our communities and facing substantial costs from these impacts. But the costs that our children and grandchildren will face if we fail to act now are simply unacceptable.

The National Climatic Data Center reports that the United States experienced seven climate disasters that each caused more than a billion dollars of damage in 2013, including devastating floods and extreme droughts in a number of western states. These are precisely the type of impacts projected to affect American communities with increasing frequency and severity as climate-destabilizing emissions continue to accumulate in the atmosphere.

The Third National Climate Assessment, released earlier this year, found that if greenhouse gas emissions are not reduced it is likely that American communities will experience:

- increased severity of health-harming smog and particulate pollution in many regions;
- intensified precipitation, hurricanes, and storm surges;
- reduced precipitation and runoff in the arid West;
- reduced crop yields and livestock productivity;
- increases in fires, insect pests, and the prevalence of diseases transmitted by food, water, and insects; and
- increased risk of illness and death due to extreme heat.

We must act now to reduce carbon pollution and mitigate these impacts. Fossil fuel-fired power plants are the largest source of greenhouse gases in our nation, and the solutions are at hand to reduce carbon pollution from the power sector. Reducing carbon pollution will also result in important reductions in health-harming co-pollutants such as mercury, nitrogen oxides, sulfur dioxide, and particulates. Reducing these co-pollutants will reduce asthma attacks, heart attacks, hospital admissions, missed school and work days, and premature deaths.

C. Best System of Emission Reduction

"redefining" sources, as that concept from the PSD program is inapplicable in the CPP's flexible, nationwide emission guidelines for a broad category of sources.[305]

N. Section 111(d) requires action on greenhouse gas emissions from EGUs, regardless of whether EGUs are subject to Hazardous Air Pollutant ("HAP") regulations.

Section 111(d)(1) sets out a mandatory command that EPA "shall" prescribe regulations providing for state plans for "any air pollutant" that is not in three enumerated categories. 42 U.S.C. § 7411(d)(1). The first two of these excluded categories of pollutants consist of criteria pollutants. *See id.* § 7411(d)(1)(i) (requiring regulation of pollutants "for which air quality criteria have not been listed or which is not included upon a list published under section 108(a)"). Because CO_2 is not a criteria pollutant, it is undisputed that this exclusion does not apply here.

The final category of pollutants excluded from the mandatory duty to promulgate section 111(d) regulations is defined by reference to section 112 of the Act. In the 1990 Clean Air Act Amendments, Congress enacted, and the President signed into law, two provisions containing different language effectuating this cross-reference. Each struck some of the same language in the preexisting section 111(d) (which was itself a reference to a specific provision in section 112 that was eliminated in the 1990 amendments). The two provisions—one originating in the House and one in the Senate—did not refer to one another.

The two 1990 cross-references have been the source of debate concerning the proper scope of regulation under sections 111(d) and 112. In litigation seeking to block the instant rulemaking and prohibit regulation of CO_2 emissions from existing sources, some parties have argued that the amendments must be read to deny EPA the authority to promulgate section 111(d) guidelines for CO_2 emissions from power plants, given that EGUs are listed and regulated under section 112(b).[306]

Contrary to these claims, EPA's authority and obligation to proceed under section 111(d) with respect to power plants is clear. Despite the unusual circumstance of two separate and simultaneously enacted changes to the same statutory text, nothing in the 1990 amendments can be fairly read to call into question EPA's authority to promulgate emissions guidelines for CO_2 emissions from EGUs.

Whatever uncertainties and interpretive challenges the two differing 1990 amendments may pose, it would not even be reasonable—let alone *mandatory* —to read either amendment, or both together, to

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[305] As shown above [cross-reference], reduced utilization of high-emitting sources is a well-established regulatory tool that EPA rightly should consider in its BSER determination. Nevertheless, opponents of the CPP may try to suggest that such curtailments in operations inappropriately "redefine" the regulated entities. To the extent such an inaccurate claim is made about curtailments (or any other aspect of the CPP), the responses would be similar to those presented here on cofiring: The CPP does not redefine any particular source, and in any event the limit on "redefining" sources from the PSD program is not relevant to the system-based approach of section 111(d).

[306] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341); Brief of Amici Curiae West Virginia, et al., 2, *Murray Energy Corp. v. EPA*, No. 14-1112 (D.C. Cir. June 25, 2014) (Doc. 1499435).

preclude regulation of pollutants such as CO_2, that are *neither* listed under section 112(b) *nor* actually regulated under that provision as to any source category.

While the 1990 House and the Senate amendments differ in wording, and arguably to some extent in legal effect, they are similar in that both were intended to provide an updated cross-reference to newly amended section 112 and that Congress, in each amendment, wanted to make sure that section 111(d) guidelines would not be redundant with amended section 112. But there is absolutely no sign that Congress intended to place large categories of harmful pollution beyond the scope of any Clean Air Act regulation, as the litigants and other commenters' theories would posit. Congress surely did not want to prohibit regulation under section 111(d) of pollution that is not regulated under section 112, *i.e.*, emissions of dangerous non-HAP pollutants such as CO_2.

Under no *reasonable* reading of section 111(d) as amended in 1990 can EPA's authority to address non-HAP emissions from existing sources be doubted. The agency need not resolve in this rulemaking every conceivable issue that may arise from the peculiar interpretive issues presented by the dual 1990 amendments; it need not decide here, for example, whether and when HAPs from source categories that are not regulated under section 112 may be regulated under section 111(d). But EPA should clarify here, in the strongest terms, that the text, structure, legislative history, and policy logic of the Clean Air Act all confirm that the dangerous but non-"hazardous" emissions from a category of existing sources are not otherwise immunized from such regulation merely because *other* pollutants emitted by those sources are either listed or regulated under section 112(b).

1. In CAA sections 110, 111(d), and 112, Congress established a comprehensive framework for controlling pollution from existing sources, in which each section addressed a separate class of pollutants.

Since Congress first enacted the Clean Air Act in 1970, sections 110, 111(d) and 112 have fit together to ensure that *all* air pollution from existing sources is adequately controlled. Congress crafted these sections to focus on different pollution, forming an interlinked and complementary structure. Section 110 establishes a process for controlling pollutants that are subject to ambient air-quality standards. EPA determines the air-quality standards that will be sufficient to protect human health and the environment, while states are responsible for devising plans that ensure the air-quality standards are met. Because these "criteria pollutants" are emitted by a variety of sources and public health can usually be protected by limiting aggregate emissions in a particular area, states have significant discretion in setting standards under section 110.

Section 112 requires controls on emissions of hazardous air pollutants. In the Clean Air Act of 1970, Congress defined a "hazardous air pollutant" as a pollutant that is not subject to air-quality standards and that "may cause, or contribute to, an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness."[307] The Act originally required EPA to publish a list of hazardous air pollutants and establish standards that "provide[] an ample margin of safety to protect the public health

[307] Clean Air Amendments of 1970, Pub. Law 91-604, § 112(a)(1), 84 Stat. 1676, 1685 (1970).

from such hazardous air pollutant[s],"[308] but EPA failed to carry out this mandate. Frustrated by EPA's inaction, Congress overhauled section 112 in 1990 by establishing its own list of nearly 200 hazardous air pollutants and requiring EPA to set stringent technology-based standards for all major sources and many non-major ("area") sources of hazardous air pollutants, as discussed below.

Section 111(d) requires controls for source categories that "cause[] or contribute[] significantly to" air pollution which "may reasonably be anticipated to endanger public health or welfare," if the pollution is not regulated under either section 110 or 112. Thus, section 111(d) functions as a backstop for sections 110 and 112, preventing dangerous existing-source pollution from being left unregulated.

Congress' systematic approach allows these sections to sections to form an orderly framework. Sections 110 and 112 focus on specific classes of pollutants and section 111(d) acts as a gap-filler, addressing dangerous pollution not regulated under the sections tailored to address hazardous and ambient air pollution problems. The legislative history of the 1970 Clean Air Act confirms that this complementary framework was deliberate:

> It should be noted that emission standards for pollutants which cannot be considered hazardous (as defined in section 115 [the precursor to section 112]) could be established under section 114 [the precursor to section 111(d)]. Thus there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.[309]

2. The 1990 Clean Air Act amendments strengthened section 112's hazardous air pollution program while maintaining the basic relationship among the Act's stationary source provisions.

In 1990, Congress responded to the fact that few sources of hazardous air pollutants had been addressed under section 112 by revising section 112 in a manner that forced EPA to regulate multitudinous source categories.[310] Specifically, Congress amended section 112 to list nearly 200 toxic air pollutants and

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[308] *Id.* § 112(b)(1)(A)-(B).
[309] Sen. Rep. No. 91-1196, at 20 (1970).
[310] The legislative history emphasizes Congress' goal of ensuring that EPA would promulgate stringent regulations for hazardous air pollutants. For instance, during the debate on the conference bill, Senator Cohen expressed his support for the amendments by stating:

> One of the most health-threatening forms of air pollution comes in the form of toxic air emissions from a wide variety of sources. Some emissions occur on an everyday basis, while some are a result of accidents that often have drastic consequences. The EPA has done a woefully inadequate job of establishing emissions standards for the hundreds of toxic pollutants that exist. In 18 years, the agency has regulated only some sources of seven chemical pollutants. Several hundred chemicals remain unregulated, to the detriment of human health. The bill requires the EPA to set standards for approximately 200 hazardous air pollutants, and then define sources of those pollutants for the purpose of implementing the standards. All sources must install the strongest technology available. After this occurs, the EPA must then review emission levels to determine whether a significant health risk continues to exist despite the application of the best technology. If that health risk does exist, the source must achieve further reductions so that the risk to human health is reduced. This new air toxics control program

require EPA to regulate all major sources of these hazardous air pollutants.[311] In addition, Congress required EPA to regulate many area sources of hazardous air pollutants (those "representing 90 percent of the area source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas").[312] Congress understood that dozens of source categories would be subject to regulation under section 112, as confirmed by section 112's implementation schedule.[313] Congress successfully catalyzed EPA action. EPA has promulgated hazardous air pollutant regulations for nearly 200 source categories and subcategories.[314] The source categories regulated under section 112 include all of the most significant sources of this nation's dangerous air pollution.

At the same time, Congress took pains to ensure that its strengthening of section 112 would not inadvertently impair any of the Clean Air Act's other vital protections. Congress explicitly provided in section 112 that "No emission standard or other requirement promulgated under this section shall be interpreted, construed or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to section [111] of this title, part C or D of this subchapter, or other authority of this chapter or a standard issued under State authority."[315] Consequently, EPA retains its obligation to—for example—regulate non-HAPs as well as HAPs from new stationary sources under section 111(b), regardless of whether those sources are also regulated under section 112. Similarly, states and EPA are required to ensure that state implementation plans under section 110 achieve attainment with National Ambient Air Quality Standards for criteria pollutants, even if those plans include requirements for existing sources that are also subject to section 112 standards. Congress unambiguously intended for the requirements of section 110, 111 and 112 to continue operating in careful coordination to protect the public from all harmful pollutants emitted by stationary sources.

In the 1990 amendments, Congress also carved out one categorical exception from the seamless threefold framework for controlling stationary source emissions. By enacting section 129, Congress crafted a unique regime for one type of source: solid waste incineration units. Congress decided to exclude these units from regulation under section 112 and instead subject them to tailored regulation under sections 129 and 111.[316] Thus, in the only case where Congress excluded a class of sources from regulation under sections 110, 111(d), or 112 because other CAA controls were sufficient, it provided for rigorous, source

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> is a very significant step forward in the effort to control air pollution. I believe it will result in significant improvements in the protection of human health from cancer risks and other threats.

Senate Debate on the Clean Air Act Amendments of 1990 Conference Report (Oct. 26, 1990), *reprinted in* U.S. Senate Comm. on Envt. & Pub. Works, Legislative History of the Clean Air Act Amendments of 1990, at 1105 (1993) (herinafter 1990 CAA Leg. Hist).

[311] 42 U.S.C. §§ 7412(b)(1), (d)(1).

[312] *Id.* §§ 7412(d)(1), (c)(3).

[313] *Id.* § 7412(e)(1). Congress required EPA to regulate at least 40 source categories and subcategories within two years of the 1990 amendments, and at least 25% of the source categories listed for regulation within four years. This indicates an assumption that the first 40 source categories regulated would be less than a quarter of the total number of regulated source categories (*i.e.*, that EPA would regulate no less than 160 source categories).

[314] EPA, National Emission Standards for Hazardous Air Pollutants (NESHAP), http://www.epa.gov/ttn/atw/mactfnlalph.html.

[315] 42 U.S.C. § 7412(d)(7).

[316] Clean Air Act Amendments, Pub. L. 101-549, § 305, 104 Stat. 2399, 2583 (1990) (codified at 42 U.S.C. § 7429(h)(2)).

category-specific regulation elsewhere in the CAA.

The treatment of EGUs is entirely different. Congress authorized regulation of EGUs under section 112 if EPA "finds such regulation is appropriate and necessary after considering the results of" a study of the health risks of EGU HAP emissions after the implementation of other CAA requirements. 42 U.S.C. § 7411(n)(1)(A). Congress did not remove EGUs from the tripartite framework for stationary source regulation, but allowed EPA to forego regulation of EGU HAP emissions if incidental control of HAPs through other CAA programs (such as the CAA cap-and-trade program to reduce acid rain, which only affects EGUs) rendered that regulation unnecessary. In deciding whether to regulate EGUs' HAP emissions, EPA was required to consider its study of the public health impacts of those HAP emissions;[317] Congress did not require this study to analyze the public health impacts of non-HAP pollution from EGUs because the Act does not force EPA to choose between regulating non-HAP emissions from EGUs under 111(d) or regulating HAP emissions under 112.

The 1990 Clean Air Act Amendments also revised the Act to more effectively protect human health and the environment in several other important ways. For instance, Congress amended section 110 to authorize EPA to require SIP revisions that are necessary to adequately mitigate interstate pollution transport,[318] and authorized EPA to apply certain sanctions if a state submits an inadequate SIP.[319] The legislation introduced new landmark programs and strengthened existing programs, prompting President George H.W. Bush to declare: "This legislation isn't just the centerpiece of our environmental agenda. It is simply the most significant air pollution legislation in our nation's history, and it restores America's place as the global leader in environmental protection."[320]

3. In 1990, Congress enacted two amendments to section 111(d) that maintained the provision's historic role in preventing dangerous pollution from existing industrial sources from going uncontrolled.

a. The 1990 Clean Air Act Amendments contained two different amendments providing for changes to the same statutory language in section 111(d)(1).

Prior to 1990, section 111(d) clearly mandated action to control dangerous air pollutants from existing sources if those emissions were not already regulated under section 108 or section 112, for source categories regulated under section 111(b):

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[317] 42 U.S.C. § 7412(n)(1)(A). Section 112(n) mandates three studies: EPA's study of the hazards EGU HAP emissions pose to public health after the imposition of other Clean Air Act requirements, which the agency must consider in its "appropriate and necessary" finding, § 7412(n)(1)(A); an EPA study of EGU mercury emissions and technologies for controlling such emissions, § 7412(n)(1)(B); and a National Institute of Environmental Health Sciences study on the threshold level of mercury exposure below which adverse human health effects are not expected, § 7412(n)(1)(C). None of these studies non-HAP emissions.

[318] *Id.*, § 101, 104 Stat. at 2407 (codified at 42 U.S.C. § 7410(k)(5)).

[319] *Id.*, § 101, 104 Stat. at 2407-08 (codified at 42 U.S.C. § 7410(m)).

[320] Remarks of President George H.W. Bush Upon Signing S. 1630, 26 Weekly Comp. Pres. Doc. 1824 (Nov. 19, 1990) (reprinting the President's signing statement of Nov. 15, 1990).

> 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 7412(b)(1)(A) of this title, but (ii) to which a standard of performance under this section would apply if such existing source were a new source.[321]

In 1990, Congress enacted two amendments to section 111(d)(1)(A)(i) addressing the same issue—when regulation under section 112 would supplant regulation under section 111(d). Some amendment to section 111(d) was necessary because the 1990 amendments deleted section 112(b)(1)(A), which was the subsection of section 112 that section 111(d) had cross-referenced since 1970. Bills originating in each chamber amended section 111(d)'s cross-reference to section 112(b)(1)(A) in different ways, and Congress ultimately enacted, and the President signed, a conference bill containing both amendments.

The amendment originating in the House revised section 111(d)(1)(A)(i) by striking the words "or 112(b)(1)(A)" and inserting in their place the following phrase: "or emitted from a source category which is regulated under section 112."[322] Congress also enacted an amendment originating in the Senate that revised the same subsection by striking the reference to "112(b)(1)(A)" and inserting in its place "112(b)."[323] The House amendment is located in section 108 of the Statutes at Large (under "Miscellaneous Guidance"); the Senate amendment is found in section 302 (under "Conforming Amendments"). The text and structure of the Act in the Statutes at Large (104 Stat. 2399) are the same as in the public law passed by both chambers and signed by President George H.W. Bush (101 P.L. 549).

The Office of the Law Revision Counsel[324] codified only the House amendment in the United States

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[321] 42 U.S.C. § 7411(d)(1) (West 1977).
[322] Pub. L. 101-549, § 108, 104 Stat. at 2467.
[323] *Id.*, § 302, 104 Stat. at 2574.
[324] Some commentators have suggested that codification decisions of the House Office of the Law Revision Counsel are entitled to some form of deference. However, the Office is not the expert agency charged with administering the CAA, and therefore not entitled to *Chevron* deference regarding the interpretation of that statute. *Chevron*, 467 U.S. at 844 ("We have long recognized that considerable weight should be accorded to an executive department's construction of a statutory scheme it is entrusted to administer, and the principle of deference to administrative interpretations has been consistently followed by this Court whenever decision as to the meaning or reach of a statute has involved reconciling conflicting policies, and a full understanding of the force of the statutory policy in the given situation has depended upon more than ordinary knowledge respecting the matters subjected to agency regulations.") (footnote and quotation omitted).

Accordingly, the Office does not even purport to interpret or amend the law in the codification process: "The translations and editorial changes made to sections of non-positive law titles are purely technical and do not change the meaning of the law." Office of the Law Revision Counsel, Detailed Guide to the United States Code Content and Features, *available at* http://uscode.house.gov/detailed_guide.xhtml. Even where there are plain errors in grammar, punctuation, or spelling, the Office does not correct them in the text of the code, but merely inserts a footnote indicating the probable error. *Id.*

The Office of the Law Revision Counsel could not purport to determine the text of section 111(d) without running afoul of the Supreme Court's jurisprudence on the separation of powers. Expunging the text of the Senate amendment from section 111(d) is a legislative act that can only be accomplished through the legislative process. *See INS v. Chadha*, 462 U.S. 919, 952-54 (1983) ("Amendment and repeal of statutes . . . must conform with [the

Code, 42 U.S.C. § 7411(d)(1)(A)(i). The codifier's notes to this section state that the Senate amendment ''could not be executed.'' Regardless, the Statutes at Large—not the United States Code—controls here. The Statutes at Large constitute the legal evidence of the laws for code titles that have not been enacted into positive law.[325] Because Title 42 of the United States Code has not been enacted into positive law,[326] the legal evidence of the relevant law is the statutes at large, which contains both amendments.[327]

b. The Senate amendment clearly requires 111(d) regulation of CO_2 from EGUs.

The Senate amendment is clear and consistent with the historic role of section 111(d) as a "backstop" to ensure protection of public health from existing-source emissions not regulated under section 112 or section 110. Read with the rest of section 111(d), the Senate amendment continues the longstanding policy of covering all non-HAP, non-criteria pollutants under section 111(d). The amendment was necessary to conform to the conference committee's amendments to section 112(b). Previously, section 112(b)(1)(A) required EPA to publish a list of HAPs it intended to regulate under section 112. The 1990 amendments removed subsection 112(b)(1)(A) entirely. The new section 112(b)(1) establishes an initial list of over 180 HAPs and section 112(b)(2)-(3) gives EPA authority to both add new HAPs to the list and to de-list certain HAPs. The Senate amendment simply updated EPA's section 111(d) authority to reflect the amended list of HAPs regulated under section 112.

While some have argued that EPA should disregard the text of the Senate amendment because its status as a "conforming amendment" renders it a poor indication of congressional intent and a likely scrivener's error, the Senate amendment cannot be disregarded. The D.C. Circuit has looked to conforming amendments in other statutes and given full effect to "the plain meaning of the statutory language in which Congress has directly expressed its intentions." *Washington Hospital Center v. Bowen*, 795 F.2d 139, 149 (D.C. Cir. 1986); *see also CBS v. FCC*, 453 U.S. 367, 381 ("Perhaps the most telling evidence of congressional intent, however, is the contemporaneous [conforming] amendment"). Further, the Senate amendment does not resemble a scrivener's error at all. A scrivener's error is "a mistake made by someone unfamiliar with the law's object and design," *United States Nat'l Bank v. Independent Ins. Agents of Am.*, 508 U.S. 439, 462 (1993), and produces language with "no plausible interpretation," *Williams Cos. v. FERC*, 345 F.3d 910, 913 n.1 (D.C. Cir. 2003). The Senate amendment is plainly not a scrivener's error. In keeping with the same protective statutory structure that Congress first crafted in the 1970 Clean Air Act, the Senate amendment has the entirely coherent purpose and effect of updating the section 111(d) cross-reference in light of amendments to section 112 that rendered the previous cross-reference meaningless by deleting previous subparagraph 112(b)(1)(A). Furthermore, because the text of the Senate amendment is unambiguous, EPA "can remain agnostic on the question whether Congress intentionally left [that] particular language in [the] statute or simply forgot to take it out. The suggestion that Congress may have 'dropped a stitch,' is not enough to permit [EPA] to ignore the statutory text."

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bicameralism and presentment requirements of] Art. I.") "Congress must abide by its delegation of authority until that delegation is legislatively altered or revoked." *Id.* at 955.

[325] 1 U.S.C. §§ 112, 204(a); *U.S. Nat. Bank of Oregon v. Indep. Ins. Agents of Am., Inc.*, 508 U.S. 439, 448 (1993); *United States* v. *Welden*, 377 U.S. 95, 98 n.4 (1964). *Stephan v. United States*, 319 U.S. 423, 426, (1943).

[326] *See* Office of Law Revision Counsel, United States Code, listing titles that have been enacted into positive law with an asterisk, http://uscode.house.gov/browse.xhtml.

[327] *See*, *supra*, note 325; Clean Air Act Amendments, 104 Stat. 2399, 2467, 2474 (1990).

See United States ex rel. Totten v. Bombardier Corp., 380 F.3d 488, 496 (D.C. Cir. 2004) (quotations and citation omitted).[328] There is no exception here to the rule requiring EPA "to give effect, if possible, to every word Congress used." *See Reiter v. Sonotone Corp.*, 442 U.S. 330, 339 (1979).

c. The House amendment is most reasonably read to require regulation of CO_2 emissions from EGUs.

In contrast to the Senate amendment, the House amendment is subject to multiple interpretations. The ambiguous House amendment would require EPA's expert interpretation even if Congress had not also amended identical language in section 111(d) through the Senate amendment. *See Chevron, U.S.C., Inc. v. Natural Resources Defense Council*, 467 U.S. 837, 843 (1984). Because the Senate amendment unambiguously commands regulation of non-HAP pollutants such as CO_2, and because the House amendment is reasonably interpreted (even without reference to the Senate Amendment) to permit such regulation, EPA plainly has authority to regulate CO_2 emissions under section 111(d), and the agency need not resolve here whether there are scenarios in which some pollutant or source might be regulable under one amendment but not the other, and how to resolve that problem.

i. The House amendment provides for regulation of emissions that are not controlled under the hazardous air pollution program.

The House amendment is subject to multiple readings that would require regulation of CO_2 from sources like EGUs. As changed by the House Amendment, section 111(d) requires EPA to prescribe existing source regulations "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 of this title." (emphasis added). The most reasonable interpretation of the House amendment is to construe it to not authorize regulation under 111(d) as to particular pollutants that are actually regulated under Section 112(n) as to the source category in question. On this interpretation, Congress intended to safeguard section 111(d)'s gap-filling role by expanding the scope of the section to cover HAP emissions that would otherwise be unregulated under sections 112 or section 111(d).

Readings of the House amendment offered by parties seeking to block regulation of CO_2 under Section 111(d) have asserted that the provision necessarily bars regulation of any and all pollutants emitted by any source that is regulated under Section 112, even if it the specific *pollutant* in question is not a HAP and is therefore not regulated under 112.[329]

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[328] *See also Owner-Operator Indep. Drivers Ass'n v. Landstar Sys.*, 622 F.3d 1307, 1327 (11th Cir. 2010) ("There is no reason for this Court to rewrite a statute because of an alleged scrivener error unless a literal interpretation would lead to an absurd result."); *Lewis v. Alexander*, 685 F.3d 325, 351-51 (3d Cir. 2012) (regardless of whether statutory text was the result of a drafting error, it was not a mere scrivener's error fit for judicial correction because Congress could have rationally chosen to enact the text at issue); *Nijjar v. Holder*, 689 F.3d 1077, 1084 (9th Cir. 2012) (same).

[329] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341); Brief of Amici Curiae West Virginia, et al., 2, *Murray Energy Corp. v. EPA*, No. 14-1112 (D.C. Cir. June 25, 2014) (Doc. 1499435).

But the text of section 112 is readily susceptible to reasonable interpretations under which the section 112-related exclusion from section 111(d) regulation is pollutant-specific. EPA may interpret the House amendment by resolving ambiguity in the phrase "emitted from a source category *which is regulated under section 112*." A source category is "regulated" under section 112 not in the abstract, but with respect to particular pollutants. The term "regulated" can therefore be read to mean "regulated with respect to that pollutant under section 112," rather than "regulated as to any pollutant under section 112."

In other words, the House text could reasonably be understood to mean either (1) that EPA may not use section 111(d) when the source category is "regulated under section 112 for *the pollutant in question*," *i.e.*, the same pollutant that is the candidate for regulation under section 111(d), or (2) that EPA may not use section 111(d) when the source category is "regulated under section 112 for *any* pollutant." The former is a sensible interpretation of the ambiguous term "regulated," and one that fits with a context that includes pollutant-specific phrasing of section 111(d) and a reference to a statutory provision, section 112, that "regulates" only hazardous pollutants. While the latter interpretation is plausible as a matter of ordinary understanding, it is not inevitable—and, as explained below, its practical consequences are starkly discordant with the statutory structure and purpose. Furthermore, it is common and proper under the Clean Air Act to construe potentially broad statutory language in light of the context in which the language appears, in order to produce a result that fits with the purpose and mechanics of the particular program in question. *See Utility Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2440 (2014) ("*UARG*") (citing numerous instances in which EPA has narrowed term "any air pollutant" to fit with context). A pollutant-specific reading of the Section 111(d) exclusion is easily permissible given the context here.

The House language may also be read to authorize EPA to regulate any air pollutant which is not a criteria pollutant and "any air pollutant [which is regulated under section 112] . . . which is not . . . emitted from a source category which is regulated under section 112." Under *Young v. Community Nutrition Institute*, an agency has discretion under *Chevron* to determine which terms are the object of a dangling modifier. 476 U.S. 974, 891 (1986) (granting *Chevron* deference to FDA's interpretation concerning which term was modified by a dangling participle in the Federal Food, Drug, and Cosmetic Act, even though a contrary "reading of the statute may seem to some to be the more natural interpretation"). Here, EPA can effectuate legislative intent by reading "which is regulated under section 112" to modify both "any air pollutant" and "source category."

Alternatively, the language "any air pollutant . . . emitted from a source category which is regulated under section 112" could be read to refer to hazardous air pollutants. This reading derives from the statutory context, in which hazardous air pollutants are the only pollutants regulated under section 112. As noted above, the Supreme Court has recently emphasized that the broad term "any air pollutant" as used in the Clean Air Act can take meaning from the context in which it is used. *See UARG*, 134 S. Ct. at 2440 (citing instances in which EPA has narrowed term "any air pollutant" to fit with context, such as EPA's having construed various provisions of section 111 that reference "any air pollutant" as limited to pollutants "*for which EPA has promulgated new source performance standards*"). Here, it is logical to understand Congress to have wanted to preclude section 111(d) regulation based on section 112 regulation only as to pollutants that are actually (or at least potentially) regulated under section 112. Moreover, under this interpretation, the House amendment would have essentially the same meaning as the Senate amendment and continue Congress' longstanding policy of using section 111(d) to control

dangerous pollution that is not controlled under the criteria pollution provisions or section 112.

ii. The legislative history of the House amendment supports a narrow reading of the section 111(d) exclusion.

Reading the House version of the section 111(d) exclusion in a pollutant-specific way is not only consistent with the language of the statute, but also promotes the purpose that EPA has reasonably attributed to the House amendment, namely, "expand[ing] EPA's authority under section 111(d) for regulating pollutants emitted from particular source categories that are not being regulated under section 112,"[330]—thereby protecting against a regulatory gap that would provide no controls against HAP emissions from certain sources not regulated under section 112.

The version of the 1990 Clean Air Act Amendments that initially passed the House clarifies the purpose of the House amendment to section 111(d). As EPA has explained, the House amendment first passed the House in a bill that included several new opportunities for EPA to exercise discretion in whether to regulate HAP emissions under section 112.[331] That bill would have provided EPA significant additional discretion regarding when to promulgate regulations under section 112. Perhaps most importantly, the House bill would have allowed EPA to decline to regulate source categories under section 112 if EPA determined they were "already adequately controlled under this Act or any other Federal statute or regulation."[332] Furthermore, the House bill would have made regulation of non-major sources under section 112 entirely discretionary.[333] In this context, EPA reasonably noted the likelihood that "the House did not want to preclude EPA from regulating under section 111(d) those pollutants emitted from source categories which were not actually being regulated under section 112."[334] Even under the conference bill that became law, the prospect of certain HAP emissions not being regulated under section 112 may have motivated the expansion of section 111(d) to cover certain dangerous HAP emissions that might otherwise escape regulation, and that would not have been subject to section 111(d) standards as it was framed prior to 1990.[335]

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[330] Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List, 70 Fed. Reg. 1594, 16031 (Mar. 29, 2005).
[331] *Id.*
[332] HR 3030, § 301, reprinted in 1990 CAA Leg. Hist. 3737 at 3933.
[333] "The Administrator may designate a category or subcategory of area sources that he finds, based on actual or estimated agregate [sic] emissions of a listed pollutant or pollutants in an area, warrants regulation under this section." *Id.*, 1990 CAA Leg. Hist. 3737 at 3933. In contrast, the conference bill required EPA to regulate certain "area source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas." Pub. L. 101-549, § 301, 104 Stat. at 2537 (codified at 42 U.S.C. § 7412(c)(3).
[334] 70 Fed. Reg. at 16031.
[335] Section 112 does not mandate controls for all source categories that emit HAPs. For instance, section 112 does not provide for the regulation of HAPs from oil and gas wells outside of certain metropolitan areas, unless those sources meet the statutory definition for "major sources." 42 U.S.C. § 7412(n)(4)(B). Also, section 112 requires EPA to regulate non-major sources "representing 90 percent of the [non-major] source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas," but otherwise only provides for regulation of non-major sources of HAPs if EPA determines they "present[] a threat of adverse effects to human health or the environment (by such sources individually or in the aggregate) warranting

The purpose of the House amendment is further illuminated by its context in the House bill *as introduced*. The House had initially proposed an overhaul of section 112 under which EPA would only be required to promulgate regulations for half the source categories it determines to be major and area sources of HAPs.[336] EPA would have been required to review the remaining fifty percent of listed source categories, and "designate the additional categories and subcategories [the EPA Administrator] finds, in his discretion, warrant regulation under this section."[337] This proposed system clearly entailed the potential for major sources of HAPs to escape regulation under section 112. Aware of this looming gap, the House proposed expanding section 111(d) to avoid leaving HAP emissions from numerous major sources unregulated.[338]

Interpretations that allow section 111(d) to continue providing for non-HAP regulation where needed to protect public health and welfare are true to the Clean Air Act's overarching structure for existing-source regulation. In addition to precluding any gaps in the regulatory framework for dangerous pollution from existing sources, these readings of the House amendment effectuate Congress' desire to make the CAA more protective through each revision. If EPA interprets the House amendment in this fashion, there will be no conflict in how the House and Senate amendments apply to the present rulemaking.

These readings have the benefit of not creating a bizarre and harmful gap in coverage of harmful pollutants that is entirely out of step with the tenor of the Act's regime and of the 1990 amendments. These interpretations are true to the Clean Air Act's overarching structure for existing-source regulation, as they allow section 111(d) to continue providing for coverage of non-HAP emissions where needed to protect public health and welfare.

These pollutant-specific readings of the House amendment are also consistent with the Supreme Court's observations about section 111(d) in *American Electric Power Company v. Connecticut*, 131 S. Ct. 2527 (2011). The Court described section 111(d)'s exclusions by stating: "There is an exception: EPA may not employ §[111(d)] if existing stationary sources of the pollutant in question are regulated under the national ambient air quality standard program, §§[108–110], or the "hazardous air pollutants" program, §[112]." *Id.* at 2537, n.7. This statement reflects the understanding that the exclusion for emissions regulated under section 112 works in parallel with the exclusion for emissions regulated under the NAAQS program. Indeed, the Court indicated that these exclusions comprise a single exception to section 111(d). There is no question that sources subject to regulation for criteria pollutant emissions

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regulation under this section." *Id.* § 7412(c)(3). Major sources are generally stationary sources with the potential to emit "10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants." *Id.* § 7412(a)(1).

[336] H.R. 3030, § 301 (introduced July 27, 1989, and referred to the Committee on Energy and Commerce), reprinted in 1990 CAA Leg. Hist. at 3936-37.

[337] *Id.* at 1990 CAA Leg. Hist. at 3937.

[338] It may also be noteworthy that neither the House bill nor conference bill posed any equivalent need to expand section 111(d) to cover criteria pollutants. This is likely due to the different nature of HAPs and criteria pollutants. Very small doses of HAPs can cause adverse impacts on public health and sources of HAPs impose the greatest burdens on nearby communities. Consequently, addressing HAP impacts requires controlling all major sources of HAPs. In contrast, the NAAQS program gives states discretion over which sources of criteria pollutants should be subject to regulation because states can adequately protect public health so long as they ensure ambient concentrations do not exceed the NAAQS.

under the NAAQS program are also subject to regulation for other emissions under section 111(d). Similarly, there should be no question that sources are subject to regulation for pollution that is not controlled by the HAPs program, even where sources are also regulated under section 112.

iii. In context, the House amendment cannot plausibly be read to end section 111(d)'s application to dangerous pollution that happens to be emitted by source categories regulated under section 112.

Although the House amendment might be read—acontextually—to diminish the scope of section 111(d), such a reading is inconsistent with the structure, purpose, and legislative history of the Clean Air Act.

Although, as demonstrated above, there are multiple ways to read the House amendment to continue 111(d)'s role as a backstop against unregulated, dangerous pollution, other readings of this ambiguous amendment have been proposed that would fundamentally alter the role of section 111(d). The most expansive reading of the House amendment would exclude from section 111(d) all pollutants emitted by sources that are regulated by section 112—even when those pollutants are emitted by a source *not* regulated under section 112. This reading would effectively nullify section 111(d) because there are few (if any) non-HAP pollutants that are *not* emitted by sources in one of the dozens of source categories regulated under section 112.[339] More vitally, this would leave a host of dangerous air pollutants wholly unaddressed by the Clean Air Act. This is made clear by the fact that none of EPA's pre-1990 emission guidelines could now be promulgated under such a regime, leaving communities vulnerable to pollutants such as sulfuric acid mist, reduced sulfur compounds, and fluoride.[340]

Some have argued that the House amendment must be read to exclude any regulation of all source categories regulated under section 112.[341] Even EPA has opined that "a literal" reading of the House amendment would exclude non-HAPs from regulation under section 111(d).[342] But no party has offered a plausible explanation for how Congress could have intended to obliterate the scope of section 111(d) through the House amendment.

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[339] *See* EPA, National Emission Standards for Hazardous Air Pollutants (NESHAP), http://www.epa.gov/ttn/atw/mactfnlalph.html (listing the nearly 200 source categories and subcategories affected by standards set under section 112).

[340] When Congress enacted the 1990 Clean Air Act Amendments, EPA had only issued four 111(d) emission guidelines, addressing total reduced sulfur from kraft paper mills, fluoride emissions from aluminum reduction plants, fluoride emissions from phosphate fertilizer plants, and sulfuric acid mist from sulfuric acid production units. Each of these source categories is now regulated under section 112 except for sulfuric acid production units. Yet sulfuric acid mist is emitted by other sources regulated under section 112, such as EGUs. *See* 76 Fed. Reg. 24976, 25,064 (May 3, 2011).

[341] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341)..

[342] Proposed National Emissions 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, 4685 (Jan. 30, 2004). In fact, however, a "literal" reading of section 111(d), both before and after the 1990 amendments would require section 111(d) regulation even for HAPs. That is because the exclusions for criteria pollutants and HAPs are structured as a mandate to regulate various classes of pollutants separated by an "or" in the alternative for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or 7412(b)(1)(A) of this title.

There is no evidence that it was Congress' intent to drastically roll back the protections in section 111(d). If Congress had intended such a radical departure from the statutory structure of the CAA, Congress would have made it explicit in the statute or some member would have at least mentioned it in the extensive legislative history of the 1990 amendments to the CAA. *See Chisom v. Roemer*, 501 U.S. 380, 396 n.23 (statutory interpretation that would work a "sweeping" and "unorthodox" change warrants skepticism). There is simply no evidence in the face of the statute or its legislative history that Congress intended such a major change in policy. Since Congress gave no indication regarding its intention to repeal the protections it established in 1970, reading such a repeal into an ambiguous statute would be strongly disfavored.[343] Here, as noted above, there are other provisions of the 1990 amendments—including section 112(d)(7)—that affirmatively indicate that Congress did *not* intend for section 112 regulations to displace or alter section 111 standards and Clean Air Act permitting programs.

A broad reading of the exclusion in the House amendment would create a hole in the Clean Air Act that is not only sweeping, but also highly anomalous. First, it is fanciful to believe Congress silently worked a major rollback of section 111(d) that is so jarringly discordant with the protective thrust of the 1990 Clean Air Act Amendments. It is simply not credible that Congress purposefully opened a major loophole—completely counter to the historic role of section 111(d)—that would leave dangerous air pollutants entirely unregulated, even as it strengthened environmental controls and systematically limited EPA's discretion to leave air pollution unregulated, purposely opened an unprecedented gap in the Clean Air Act's framework for stationary-source regulation. This reading also assumes that Congress created this unprecedented loophole surreptitiously, leaving major categories of pollutants wholly unregulated for the first time since 1970, at the same time that the supporters of the 1990 amendments uniformly praised the bill for *strengthening* the Clean Air Act.[344]

Second, this reading of the House amendment would insert an exclusion into section 111(d) that is unlike any other in the Clean Air Act. Congress has never allowed sources to release unlimited quantities of some pollutants simply because they must control *other* pollutants. *Cf. Desert Citizens Against Pollution v. EPA*, 699 F.3d 524, 527-28 (D.C. Cir. 2012) (holding that EPA reasonably rejected petitioners' interpretation of the Clean Air Act, which "would have the anomalous effect of changing the required stringency" for certain hazardous air pollutants at a given source "simply on the fortuity" of the source's other emissions).

Third, any attempt to actually implement the broad exclusion reveals additional anomalies. Even under the most expansive reading of the House amendment, pollutants are only excluded from regulation under 111(d) if EPA happens to regulate a source under section 112 first. If EPA first regulates a source

[343] The canon disfavoring implied repeals is discussed in section I.N.4.b.

[344] *See, e.g.*, Remarks of Rep. Dingell during the House Debate on the Conference Report, reprinted in 1990 CAA Leg. Hist. at 1187 ("America already has the toughest air quality laws in the world. With this act, we will be raising our standards even higher. We will also be fulfilling our responsibility to the American people who have told us that they are willing to make some sacrifices in pursuit of a cleaner environment."); Remarks of Rep. Green during House Debate on the Conference Report, reprinted in 1990 CAA Leg. Hist. at 1180 ("Mr. Speaker, the conference report before us today will help us to fulfill our promise to the American people of a clean, safe environment. Although some . . . may argue that the costs of enacting this bill are too great, I contend that the costs of not enacting clean air legislation this year are greater still.").

category under section 111(d) and then regulates the same source category under section 112, section 112(d)(7) provides that the HAP regulation does not diminish or replace the existing 111(d) standards. It is inconceivable that Congress would prohibit section 111(d) standards "simply on the fortuity" of EPA's timing for promulgating standards under section 112. *Accord Desert Citizens Against Pollution*, 699 F.3d at 527-28.

One company has developed a theory that attempts to explain how Congress could have intended to weaken section 111(d) in 1990: that Congress sought to strengthen section 112 without imposing "double regulation" on any source category.[345] This account is entirely unfounded. First of all, the Clean Air Act is full of examples of instances in which Congress, in the interest of protecting public health and welfare, subject pollution sources to multiple, overlapping requirements for the *same* pollutants. *See*, *e.g.*, 42 U.S.C. § 7475(a) (noting that sources subject to stationary source permitting requirements (and "best available control technology" requirement) also must comply with applicable increments and air standards under, as well as any applicable performance standards under section 111); *Id.* § 7416 (expressly preserving state regulation of stationary sources except where less stringent that Clean Air Act requirements). The 1990 legislative history makes clear that House members were aware that, under the House bill, stationary sources would continue to be regulated under multiple sections of the Clean Air Act.[346]

Most important, it is not "double regulation" for *different* pollutants from a single source category to be regulated under different regulatory programs. The notion that subjecting a source to regulation for some pollutant should immunize it from regulation as to other pollutants is odd and altogether alien to the CAA's protective design. The CAA framework often provides separate but complementary regulatory frameworks to address different types of pollution emitted by the same sources. Criteria pollutant standards also apply to the same sources whose emissions of hazardous air pollution are addressed by Section 112. For instance, the CAA's Prevention of Significant Deterioration program requires new major emitting facilities to use the "best available control technology" for criteria pollutants,[347] in addition to any standards promulgated under section 111(b) or 112. Nor do any of the CAA's stationary source provisions exclude sources from regulation because they are regulated under other federal environmental laws.[348]

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[345] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341).

[346] "Under H.R. 3030, states would be required to submit to EPA comprehensive permit programs for regulating stationary sources. The permitting requirements would extend to sources that are subject to new source performance standards, emission standards for hazardous air pollutants, requirements for preventing significant deterioration (PSD) of air quality, nonattainment new and existing source review, and acid deposition controls under Title V. They also apply to all sources of air pollution emitting over 100 tons a year." House Debate on H.R. 3030 (May 21, 1990), reprinted in 1990 CAA Leg. Hist. at 2566.

[347] 42 U.S.C. § 7475(a)(4).

[348] For certain sources regulated under other acts, the 1990 amendments required EPA to consider the efficacy of those regulations before issuing regulations under section 112. As amended in 1990, section 112 does not require EPA to regulate sources and substances regulated by the Nuclear Regulatory Commission if "the regulatory program established by the Nuclear Regulatory Commission pursuant to the Atomic Energy Act for such category or subcategory provides an ample margin of safety to protect the public health." 104 Stat. at 2542 (codified at 42

In summary, there is no reason to believe that the House amendment should be read to eviscerate section 111(d) and the House amendment can easily be read to preserve the gap-filling role of section 111(d) in the Clean Air Act's regulatory framework.

4. EPA can reasonably harmonize the two amendments to section 111(d) by adopting one of several reasonable interpretations of section 111(d), all of which require EPA to regulate non-HAP pollutants like CO_2.

a. Where one amendment clearly requires regulation of CO_2 emissions from EGUs and another amendment's treatment of such emissions is ambiguous, EPA must interpret the two amendments harmoniously.

The two amendments to section 111(d)(1)(A)(i) created a statutory ambiguity regarding the pollutants regulated under section 111(d). This ambiguity requires EPA's expert interpretation. *See Chevron*, 467 U.S. at 837.[349] EPA's expert interpretation of section 111(d) must be guided by the rule that "[t]he provisions of a text should be interpreted in a way that renders them, compatible, not contradictory."[350] EPA can reconcile the two amendments and interpret section 111(d) to require standards to address CO_2 emissions from EGUs.

b. Any conflict in the section 111(d) can be resolved by reasonably harmonizing the House and Senate amendments.

In the proposed rule, EPA has reasonably harmonized the text of the House and Senate amendments, through the following interpretation: "Where a source category is regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under section 112(b) that may be emitted from that particular source category."[351] This interpretation follows the case law

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U.S.C. § 7412(d)(9)). In addition, Congress provided that "In the case of any category or subcategory of sources the air emissions of which are regulated under subtitle C of the Solid Waste Disposal Act, the Administrator shall take into account any regulations of such emissions which are promulgated under such subtitle and shall, to the maximum extent practicable and consistent with the provisions of this section, ensure that the requirements of such subtitle and this section are consistent." 104 Stat. at 2560 (codified at 42 U.S.C. § 7412(n)(7)).

[349] *See also Scialabba v. Cuellar de Osorio*, 134 S. Ct. 2191, 2203 (2014) (plurality opinion); *Id.* at 2219 n. 3 (Sotomayor, J., joined by Breyer, J., dissenting).

[350] Antonin Scalia and Bryan A. Garner, Reading Law: The Interpretation of Legal Texts (2012) at 180; *id.* ("The imperative of harmony among provisions is more categorical than most other canons of construction because it is invariably true that intelligent drafters do not contradict themselves (in the absence of duress). Hence there can be no justification for needlessly rendering provisions in conflict if they can be interpreted harmoniously."); s*ee also Ricci v. DeStefano*, 557 U.S. 557, 579-83 (2009) (where provisions of Title VII "could be in conflict absent a rule to reconcile them," Court adopted construction that "allows the [provision at issue] to work in a manner that is consistent with other provisions of Title VII"); *Watt v. Alaska*, 451 U.S. 259, 267 (1981) (construing potentially discordant statutory provisions "to give effect to each if [it] can do so while preserving their sense and purpose").

[351] EPA, "Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units" (2014) at 26. Over the span of a decade, EPA has interpreted the House and Senate amendments to section 111(d) consistently in each of the two rulemakings where they were at issue. Courts should give significant weight to EPA's unwavering interpretation of section 111(d). *See Good Samaritan Hospital v. Shalala*, 508 U.S. 402, 417 (1993) ("[T]he consistency of an agency's position is a factor in assessing the weight that position is due.").

regarding when and how to harmonize conflicting statutory provisions.

The D.C. Circuit has given EPA detailed instructions on "its responsibility to harmonize the statutory provisions" of the Clean Air Act when two provisions conflict and the statute does not plainly indicate which provision shall prevail. *See generally Citizens to Save Spencer Cnty v. EPA*, 600 F.2d 844 (D.C. Cir. 1979) (upholding EPA's harmonization of sections 165 and 168 of the 1977 Clean Air Act, which were drawn from "two bills originating in different Houses and containing provisions that, when combined, were inconsistent in respects never reconciled in conference"); *explained in NRDC v. Thomas*, 805 F.2d 410, 436 n.39 (D.C. Cir. 1986) ("[T]his court held that the agency had broad latitude to harmonize two Clean Air Act provisions that facially dealt with the same issue differently."); *see also Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1043-44 (D.C. Cir. 2001) ("Lest it obtain a license to rewrite the statute" an agency alleging a scrivener's error "may deviate no further from the statute than is needed to protect congressional intent.") (quotations and citation omitted).

The court explained that "the maximum possible effect should be afforded to all statutory provisions . . . if the inconsistent provisions point generally in a common direction." *Spencer Cnty*, 600 F.2d at 870-71; *cf. United States v. Colon-Ortiz*, 866 F.2d 6 (1st Cir. 1989) (reading language out of a statute, where language inserted through a drafting error directly required the opposite outcome from what Congress had mandated elsewhere in the text). Harmonization of the House and Senate amendments to section 111(d) is appropriate because the two amendments point in a common direction. EPA has previously interpreted the House amendment to reflect the "House's apparent desire to increase the scope of EPA's authority under section 111(d) and to avoid duplicative regulation of HAP for a particular source category."[352] As EPA explained in its proposal for the Clean Air Mercury Rule, the House amendment can be reasonably interpreted to reflect a desire to expand the pollutants that EPA could regulate under section 111(d) so that EPA had authority to regulate HAPs emitted from source categories that were not actually being regulated under section 112 (such as existing area sources of HAPs that did not meet the statutory criterion in section 112(c)(3)). Similarly, the Senate amendment serves the general purposes of preserving EPA's authority to regulate non-HAPs under section 111(d) and avoiding duplicative regulation of HAPs. That is, the Senate's conforming amendment was necessary to give EPA authority to regulate any de-listed HAP under section 111(d). In addition, the Senate amendment avoids duplicative regulation of HAPs because it prevents EPA from regulating any HAP that is listed for regulation under section 112.

In harmonizing the House and Senate amendments to section 111(d), "it is appropriate for the agency . . . to look for guidance to the statute as a whole and to consider the underlying goals and purposes of the legislature in enacting the statute, while avoiding unnecessary hardship or surprise to affected parties." *Spencer County*, 600 F.2d at 871 (footnote omitted).

In the proposed rule, EPA has properly adhered to these principles in interpreting section 111(d). First, EPA concluded that it would be unreasonable to allow an expansive reading of the House amendment to prevail over the Senate amendment because such an interpretation would be inconsistent with "Congress' desire in the 1990 CAA Amendments to require the EPA to regulate more substances, and not to

[352] 69 Fed. Reg. at 4685.

eliminate the EPA's ability to regulate large categories of air pollutants."[353] Further, prohibiting the regulation of non-hazardous but dangerous pollutants from existing sources because hazardous emissions from those sources is appropriately regulated under Section 112 would expose American communities to health- and welfare-harming pollutants—clearly in conflict with Congress' effort in the Clean Air Act to protect Americans from harmful pollution. Thus, EPA has properly effectuated Congress' underlying goals and purposes in the Clean Air Act and subsequent amendments. Second, EPA reasoned that reading section 111(d) to exclude any air pollutant from a source category regulated under section 112 would be inconsistent with "the fact that the EPA has historically regulated non-hazardous air pollutants under section 111(d), even where those air pollutants were emitted from a source category actually regulated under section 112."[354] EPA's interpretation ensures the agency's continued ability to effectively protect public health and the environment, whereas interpreting the 1990 amendments to drastically curtail the agency's longstanding authority under section 111(d) would cause unexpected harm.

EPA's interpretation of section 111(d) is sound for several additional reasons. First, in accord with the interpretative canons against implied amendments and repeals, EPA has not read the 1990 amendments to repeal section 111(d)'s application to non-HAP emissions from sources regulated under section 112.

Reading the House amendment as certain court challengers have urged would deprive section 111(d) of most, if not all, of its traditional effect as a backstop that allows regulation of harmful pollution not covered under section 110 and 112. In the context of CO_2 emissions, this interpretation would not only preclude regulation of CO_2 emissions from the power sector; it would similarly bar any regulation in all other sectors of the nation's most significant sources of CO_2, because, like power plants, these categories too are regulated under section 112. EPA data confirms that—even outside the power sector—the chief emitters of CO_2 among stationary sources are subject to HAP regulation under section 112. According to EPA's Facility Level Information on GreenHouse gases Tool (FLIGHT), the non-power subsectors of the economy that emitted more than 10 million metric tons of CO_2 in 2013 were: Petroleum refineries; natural gas processing; natural gas transmission/compression; other petroleum and natural gas systems; petrochemical production; hydrogen production; ammonia production; other chemicals; iron and steel production, other metals; cement production; lime manufacturing; pulp and paper; other paper products; food processing; manufacturing; ethanol production; and other.[355] All of the major CO_2-emitting source categories in the defined subsectors on this list are regulated under section 112.[356] (The "other" category

[353] EPA, "Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units" at 26-27.
[354] *Id.*
[355] *See* EPA FLIGHT, available at http://ghgdata.epa.gov/ghgp/main.do.
[356] 40 CFR §§ 63.640 et seq & 63.1560 et seq (NESHAPs for petroleum refineries, including units used for hydrogen production); §§ 63.760 et seq (NESHAP for oil and natural gas production facilities, including facilities that process natural gas and certain compressors); §§ 63.1270 et seq (NESHAP for natural gas transmission and storage facilities); subparts F, G, H & I (NESHAPs for the synthetic organic chemical manufacturing industry, including manufacturing of certain petrochemical products); §§ 63.11400 et seq (NESHAP for carbon black production area sources, which manufacture "petrochemical products"); §§ 63.2430 et seq (NESHAP for miscellaneous organic chemical manufacturing, which includes units classified under 1997 NAICS code 325, such as ammonia manufacturing); §§ 63.11494 et seq (NESHAP for chemical manufacturing area sources, which includes units classified under 1997 NAICS code 325); §§ 63.7680 et seq (NESHAP for iron and steel foundries); §§ 63.7780 et seq (NESHAP for integrated iron and steel foundries); §§ 63.10880 et seq (NESHAP for iron and steel

likely includes many source categories regulated under section 112).[357] Because of the sheer number of section 112-listed source categories, and the fact that they include most of the largest pollution sources, the suggested readings would likely have similarly dramatic effects on section 111(d)'s coverage as to other dangerous, but not hazardous, pollutants.

"[I]t is well settled that amendments by implication (like repeals by implication) are disfavored." *Natural Resources Defense Council, Inc. v. Hodel*, 865 F.2d 288, 318 (D.C. Cir. 1988). "[A]bsent a clearly expressed congressional intention, repeals by implication are not favored." *See Branch v. Smith*, 538 U.S. 254, 273 (2003); *see also Nat'l Ass'n of Home Builders v. Defenders of Wildlife*, 551 U.S. 644, 664 n.8 (2007) ("It does not matter whether this alteration is characterized as an amendment or a partial repeal."). Congress expressed no clear intention to drastically narrow the scope of section 111(d), given the plain text of the Senate amendment, the categorization of the House amendment as "Miscellaneous Guidance,"[358] the legislative history's silence on such a repeal, and the general thrust of the 1990 amendments to broaden regulation of air pollutants. EPA has properly refrained from interpreting the House amendment to require such a change because Congress "does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes." *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001).

Guided by the canon against implied repeals, the Supreme Court has held that an agency may read a later-enacted provision to not override an existing, express statutory mandate. *See Nat'l Ass'n of Home Builders*, 551 U.S. at 666 (approving a harmonizing interpretation of the Endangered Species Act, where one of the act's provisions directly conflicted with a clear mandate in the Clean Water Act). If there is any conflict between the pre-1990 text of the CAA and the 1990 amendments, EPA cannot assume Congress' intended to repeal longstanding mandates in the Act unless that intention is clearly expressed. In the 1990 amendments, Congress did not clearly signal its intent to repeal section 111(d)'s application to non-HAPs emitted by sources regulated under section 112, as the Senate amendment directs EPA to continue applying section 111(d) to these pollutants. EPA's interpretation of section 111(d) appropriately harmonizes the House and Senate amendments because it does not allow the House amendment to override the existing, express statutory mandate to regulate under section 111(d) any air pollutant that is not regulated under the NAAQS program or section 112.

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foundries area sources); §§ 63.1340 et seq (NESHAP for the Portland cement manufacturing industry); §§ 63.7080 et seq (NESHAP for lime manufacturing plants); §§ 63.440 et seq (NESHAP for the pulp and paper industry); §§ 63.7480 et seq (NESHAP for industrial, commercial, and institutional boilers and process heaters that are major sources of HAPs); §§ 63.11193 et seq (NESHAP for industrial, commercial, and institutional boilers and process heaters that are area sources of HAPs); §§ 63.6080 et seq (NESHAP for stationary combustion turbines); §§ 63.6580 et seq (NESHAP for reciprocating internal combustion engines). Boilers, turbines, engines, and process heaters are the main sources of CO_2 emissions from the food processing, manufacturing, and ethanol subsectors. *See* EPA, Who Reports?, http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=93290546 (explaining that facilities in the food processing, manufacturing, and ethanol subsectors are required to report emissions from stationary combustion if they meet an emissions threshold); 40 CFR § 98.30 ("Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.").

[357] For instance sources in the "other chemicals" category may be regulated under section 112 as part of the Chemical manufacturing Industry (area sources) source category, subpart VVVVVV or Miscellaneous Organic Chemical Production and Processing source category, subpart FFFF.

[358] Public Law 101–549, § 4108(g), 104 Stat. at 2467 (Nov. 15, 1990).

Similarly, *Watt v. Alaska* illustrates how the canon against implied repeals can guide EPA in its duty "to give effect to each [amendment] if [it] can do so while preserving their sense and purpose." *See* 451 U.S. 259, 267 (1981). That case examined two statutory provisions that, by their plain terms, gave conflicting instructions regarding the distribution of mineral revenue from all federal wildlife refuges.[359] The Court examined the later-enacted statute (the 1964 amendments to the Wildlife Refuge Revenue Sharing Act) for "clearly expressed congressional intention" to repeal the prior law, and found none. 451 U.S. at 273. The Court harmonized the conflicting provisions by reading the latter-enacted law to apply only to mineral revenues from the class of wildlife refuges that motivated congressional action in 1964. That is, the Court read the latter-enacted provision to establish the revenue-distribution formula for mineral revenues from lands acquired for wildlife refuges, reasoning that the purpose of the 1964 amendments was to facilitate acquisition of lands for wildlife refuges. 451 U.S. at 272.[360]

EPA's proposed interpretation of section 111(d) is entirely consistent with the Court's approach in *Watts.* EPA has interpreted the House amendment to refer to the class of pollutants that motivated the amendment: pollutants that were actually regulated under section 112. EPA has previously concluded that "the House's amendment to section 111(d) could reasonably reflect its effort to expand EPA's authority under section 111(d) for regulating pollutants emitted from particular source categories that are not being regulated under section 112."[361] This conclusion is supported by reading the House amendments to section 111(d) together with the House's proposed amendments to section 112. As discussed above, the House bill proposed giving EPA discretion to not regulate sources under section 112 in specific circumstances. While the House's proposed amendment to section 112 might have diminished the scope of regulation under that section, the House expanded the scope of section 111(d) and avoided creating a gap in the statutory framework for existing-source regulation. In this rulemaking, EPA has harmonized the House and Senate amendments to ensure the section 111(d) exclusion only applies to pollution that is actually regulated under section 112, thus giving an effect to both the House and Senate amendments that serves their respective purposes.

Second, EPA's proposed interpretation of section 111(d) is consistent with that section's role in the structure of the Clean Air Act. Section 111(d) provides for controlling dangerous existing-source pollution that would otherwise escape regulation, where EPA has regulated a source category under section 111(b) after finding that the category of sources "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." In short, the section fills gaps in the Act's framework for existing stationary sources that cause or contribute significantly to

[359] Under the Mineral Leasing Act of 1920, ninety percent of federal oil and gas revenue goes to the states and ten percent to the U.S. Treasury, whereas 1964 amendments to the Wildlife Refuge Revenue Sharing Act require twenty-five percent of the revenue from refuge resources (including "minerals") to goes to counties and seventy-five percent to the Department of Interior.

[360] The Court explained that the purpose of the 1964 amendments was to distribute more revenue to counties "as compensation for loss of taxable properties that have been acquired by the Federal wildlife refuge system." 451 U.S. at 270. The Court observed that "Congress might be expected to have mentioned a change" that would have increased federal revenues, especially when "Congress was concerned that the Department have sufficient funds to make the increased payments mandated by the amendments." 451 U.S. at 271.

[361] 70 Fed. Reg. at 16031.

harmful air pollution. Because section 112 does not require EPA to regulate HAPs from all sources,[362] some sources may emit dangerous amounts of hazardous pollutants even after EPA fully implements section 112. EPA's harmonization of the conflicting amendments would allow section 111(d) to play its gap-filling role for uncontrolled sources of hazardous air pollution (as well as for non-hazardous but dangerous pollutants emitted by sources that are regulated under Section 112).

Third, EPA's proposed approach is consistent with the canon that exemptions from regulation should be construed narrowly. See *Comm'r v. Clark*, 489 U.S. 726 (U.S. 1989). ("In construing provisions . . . in which a general statement of policy is qualified by an exception, we usually read the exception narrowly in order to preserve the primary operation of the provision"); *see Phillips, Inc.* v. *Walling*, 324 U.S. 490, 493 (1945) ("To extend an exemption to other than those plainly and unmistakably within its terms and spirit is to abuse the interpretative process and to frustrate the announced will of the people."). Here, because the amendments exempt certain pollutants from regulation, any ambiguity in the amendments should be construed in favor of limiting the range of pollutants that are exempted.

As the expert agency responsible for implementing the Clean Air Act, EPA is uniquely aware that narrowing the scope of section 111(d) would significantly harm public health and welfare, and that these harms are contrary to the purposes of the Act. *See* 42 U.S.C. § 7401(b)(1). A court would properly defer to EPA's regulatory expertise in determining whether EPA has reasonably harmonized the differing 1990 amendments to section 111(d). *See Nat'l Ass'n of Home Builders*, 551 U.S.at 666 (upholding EPA's expert harmonization of conflicting statutes, where the agency could not "simultaneously obey the differing mandates set forth in [the two provisions]" and "the statutory language . . . does not itself provide clear guidance as to which command must give way").

c. There are additional ways to harmonize the amendments that are consistent with the language and purpose of 111(d).

The most straightforward way of harmonizing the two amendments is to interpret the ambiguous House amendment to be consistent with the crystal-clear Senate amendment with respect to the question presented here—*i.e.*, EPA may, under section 111(d), regulate a non-HAP pollutant that is emitted from source category whose HAP emissions are regulated under section 112(d). As demonstrated above, there are multiple reasonable readings of section 111(d) as amended by the 1990 House language that would allow EPA to proceed with regulating CO_2 emissions from EGUs.

An alternative means of doing so would be to interpret the 1990 amendments as having included two different versions of 111(d), one reflecting the direction provided by House amendment and one the Senate amendment. Under this approach, the statute contains, with the Senate amendment, a separate, affirmative command to regulate all non-NAAQS, non-112(b)-listed pollutants. Each amendment mandates that EPA "*shall* prescribe regulations" for a set of air pollutants. 42 U.S.C. § 7411(d)(1) (emphasis added). Neither purports to *negate* regulatory obligations required by other provisions of the

[362] As discussed above, section 112 does not provide for regulation of certain area sources in the oil and gas sector and regulation of HAPs from many area sources is discretionary under section 112.

statute.[363] Thus, even if the House amendment is read to exclude EGUs (and to direct regulation of sources not regulated under 112), the two amendments set out compatible and additive commands to regulate (EPA must issue guidelines for all non-NAAQS pollutants not on a 112 pollutant list, and for sources of all non-NAAQS pollutants not regulated under 112). This reading allows EPA to "give effect to both" provisions, *see Morton v. Mancari*, 417 U.S. 535, 551 (1974), by doing what is required by either of the amendments.

Some commentators have suggested that the two 1990 amendments should both be given effect and that, if both are incorporated into the statute, the resulting language can be read to deny EPA authority to act here.[364] The premise that both amendments can be combined together and read as a single statutory command is problematic, since both provisions direct that the same language in the preexisting legislation be stricken; and neither amendment refers to or purports to take account of the other. There is no evidence that either house of Congress, in fact, legislated with the expectation that its change to section 111(d) would be combined with another change. The statute does not provide any definitive guidance for how to incorporate the different chambers' instructions; efforts to combine the language of the two amendments into a workable whole have a kind of artificiality in light of the strong indications that Congress did not actually make any decision that the two amendments were meant to operate together. But, contrary to the premise of the some supporters of this approach, the proper way to combine the amendments yields an approach that is grammatical, that attempts to heed Congress's instructions closely as possible; and that yields a result that is consonant with the statute.

The House and Senate amendments can be effectuated together as follows: First, both amendments would strike out the preexisting reference to "112(b)(1)(A)." The House amendment would then insert "or emitted from a source category" at the point in the text where "or 112(b)(1)(A)" was removed. The Senate amendment would require "112(b)" to be inserted at the point in the text where "112(b)(1)(A)" was removed, immediately after the original "or" that the House Amendment replaced. The combined section would read:

> The Administrator shall [establish emission guidelines] for any existing source for any air pollutant . . . which is not included on a list published under section . . . 112(b) emitted from a source category which is regulated under section 112 of this title.

The resulting amended statute would direct EPA to regulate all pollutants that are not criteria pollutants or emitted by source categories listed under section 112 and actually regulated under that section. Thus,

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363 Indeed, the savings clause enacted as part of the 1990 amendments indicates that Congress recognized the importance of section 111(d) in controlling dangerous pollutants and did not want such regulation to be ousted lightly or by mere implication. That savings provision provides that "[n]o emission standard or other requirement promulgated under this section [112] shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to Section 111 [and other programs]." 42 U.S.C. § 7412(d)(7).

364 See William J. Haun, The Clean Air Act As an Obstacle to the Environmental Protection Agency's Anticipated Attempt to Regulate Greenhouse Gas Emissions from Existing Power Plants 10-11 (Federalist Society 2013), available at http://www.fed-soc.org/library/doclib/20130311_HaunEPAWP.pdf.

reading the language added by the House and Senate amendments together yields a meaning that is coherent and maintains section 111(d)'s role in protecting human health and the environment.[365]

Any permissible harmonization of the House and Senate amendments must achieve the purpose of section 111(d), which is ensuring that dangerous pollution from existing industrial sources does not escape regulation. EPA cannot adopt an interpretation of section 111(d) that creates a gaping, inexplicable hole in the CAA's framework for regulating existing industrial sources. The commentators' alternative "harmonization" fails this basic requirement.

5. If harmonizing the amendments were not possible, any reasonable interpretation of section 111(d) would still allow EPA to regulate CO_2 emissions from EGUs.

If harmonizing the amendments were impossible, EPA could rely on several canons of statutory interpretation to resolve any conflict in section 111(d). Under any available rule of construction, section 111(d) controls dangerous non-HAP emissions regardless of whether they come from source categories that are subject to regulation under section 112. EPA's application of these canons to interpret conflicting provisions would be entitled to deference.[366]

First, as EPA observed, "[t]he ambiguities stem from apparent drafting errors that occurred during enactment of the 1990 CAA Amendments."[367] If conflicting language in section 111(d) is a result of a mistake, that mistake must have been the House amendment's exclusion of "sources" regulated under section 112 instead of "emissions" regulated under section 112. As described above, the apparent purpose of the House amendment to section 111(d) was to *avoid* creating a gap in the statutory structure for controlling emissions from existing sources; if the conference committee had adopted the House's amendments to section 112, an amendment to section 111(d) would have been necessary to ensure that EPA had authority to regulate existing-source HAP emissions that EPA chose to not regulate under section 112.

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365 In contrast, the approach urged by Haun, supra, results in a formulation that would restrict section 111(d) to "any air pollutant . . . which is not included on a list published under section 7408(a) or 112(b) [Senate amendment] *or emitted from a source category which is regulated under section 112* [House amendment] of this title[.]" Haun at 10 (emphasis added by Haun). However such an interpretation would be properly interpreted, it clearly does not faithfully implement the amendments, since it results in smuggling in an extra "or" that Congress did not enact. The House Amendment struck one "or" (by striking "or section 112(b)(1)(A)"), and the Senate Amendment did not add any "or's." Yet the Haun approach manages to yield a new "or," by disregarding the instruction in the House amendment to strike the preexisting "or".

This purported harmonizing reading is also impermissible because it simply declines to give effect to the Senate amendment in this rulemaking. As discussed above, each amendment contains an exception to a regulatory mandate. But none of the exceptions in section 111(d) prohibit EPA action or otherwise detract from mandates to protect human health and the environment. This attempt at harmonization fails to give full effect to both amendments, as illustrated by its application to this rulemaking. Failure to issue guidelines for CO_2 emissions from EGUs would be a blatant violation of the Senate amendment's mandate to control all dangerous non-HAP, non-criteria pollutant emissions that are subject to standards under section 111(b).

366 *See Scialabba*, 134 S. Ct. at 2203 (plurality opinion); *Id.*. at 2219 n. 3 (Sotomayor, J., joined by Breyer, J., dissenting) (agreeing with plurality that where agency cannot "simultaneously obey" two statutory commands, "it is appropriate to defer to the agency's choice as to 'which command must give way'" (quotation marks omitted)).

367 79 Fed. Reg. at 34853.

Giving effect to the narrow interpretation of the House amendment does not promote the House's (and Congress') manifest intention to control all dangerous air pollution from existing sources. In contrast, the Senate amendment clearly retains EPA's authority to ensure effective regulation of dangerous non-HAP pollutants from existing sources under section 111(d) as a complement to regulation of HAPs under section 112. Accordingly, if EPA's attempts at harmonizing the amendments had failed, EPA could have shown that "Congress did not mean what it appears to have said" in the House amendment and that "as a matter of logic and statutory structure, it almost surely could not have meant it." *See Engine Mfrs. Ass'n v. EPA*, 88 F.3d 1075, 1089 (D.C. Cir. 1996). In such situations, EPA can interpret section 111(d) "by disregarding an obvious mistake." *See Bohac v. Dep't of Agric.*, 239 F.3d 1334, 1338 (Fed. Cir. 2001); *see also Am. Petroleum Inst. v. SEC*, 714 F.3d 1329, 1336-37 (D.C. Cir. 2013) (refusing to interpret a scrivener's error as indication that Congress intended to depart from a longstanding statutory scheme).[368]

If the two amendments were deemed incompatible, EPA could then choose which amendment is controlling, the agency has discretion in reading section 111(d) to effectuate congressional intent. *See Appalachian Power Co.*, 249 F.3d at 1044 n.3 ("[W]hen there are multiple ways of avoiding a statutory anomaly, all equally consistent with the intentions of the statute's drafters (and equally inconsistent with the statute's text), we accord standard *Chevron* step two deference to an agency's choice between such alternatives.") (quotation omitted); *see also Abdelqadar v. Gonzales*, 413 F.3d 668, 673 (7th Cir. 2005) (noting that judges cannot generally engage in "repair work" to rescue Congress from its drafting errors, "but agencies charged with superintending a comprehensive scheme traditionally have been afforded additional latitude"). In the context of the CAA's carefully crafted framework for controlling all dangerous emissions from existing sources, it would be implausible to read section 111(d) to let certain dangerous pollution go unregulated simply because EPA controlled *other* pollution from the same sources.

Second, if one of the amendments must prevail over the other, the canons against implied repeal and amendment hold that the Senate amendment must control.[369] EPA cannot presume that Congress intended to repeal its authority to regulate non-HAPs from sources regulated under section 112 unless Congress' intention to do so is "clear and manifest." *See Watt*, 451 U.S. at 267. Where there are two amendments to the same language, and those two amendments point in different directions, there is no "clear and manifest" intention. The Senate amendment is substantively similar to prior law and, therefore, should be given effect if EPA cannot discern Congress' clear and manifest intent to substantively change section

[368] If the inclusion of the House amendment did not create ambiguity in the statutory text, the plain language of the statute would control despite any errors in the drafting process. *See Lamie v. United States Trustee*, 540 U.S. 526, 542 (2004) ("If Congress enacted into law something different from what it intended, then it should amend the statute to conform it to its intent. It is beyond our province to rescue Congress from its drafting errors, and to provide for what we might think . . . is the preferred result.") (quotation omitted). But here, it is impossible for EPA to give effect to the House amendment without violating the mandate in the Senate amendment. As explained above, EPA may also respond to this scrivener's error by interpreting the House amendment in a way that gives it some effect but avoids an absurd result. *See United States ex rel. Holmes v. Consumer Ins. Group*, 318 F.3d 1199, 1209 (10th Cir. 2003) ("Under the doctrine of scrivener's error, a court may give an unusual (though not unheard-of) meaning to a word which, if given its normal meaning, would produce an absurd and arguably unconstitutional result.") (quotations omitted).

[369] These canons are discussed supra, section I.N.4.b, because they demonstrate that—if harmonization is possible—EPA's harmonization is reasonable.

111(d).[370]

Third, "[t]he established rule is that if there exists a conflict in the provisions of the same act, the last provision in point of arrangement must control." *Lodge 1858, American Fed. of Gov't Employees v. Webb*, 580 F.2d 496 (D.C. Cir. 1978). This rule applies regardless of whether the conflicting provisions are in the same statutory section. *See, e.g.*, *Merchants' Nat'l Bank v. United States*, 214 F. 200, 205 (2d Cir. 1914); *Mobile v. GSF Properties, Inc.*, 531 So. 2d 833, 837-38 (Ala. 1988).[371] Under this rule, the Senate amendment controls over the House amendment because it appears later in the Statutes at Large.

Finally, giving effect to the Senate amendment would allow EPA to avoid an absurd result. *See American Water Works Ass'n v. EPA*, 40 F.3d 1266, 1271 (D.C. Cir. 1994) ("where a literal reading of a statutory term would lead to absurd results, the term simply 'has no plain meaning … and is the proper subject of construction by the EPA and the courts'") (quoting *Chemical Mfrs. Assoc. v. Natural Resources Defense Council*, 470 U.S. 116, 126 (1985)). Reading section 111(d) to exclude from control the dangerous (though not hazardous) emissions from all sources regulated under section 112 would exclude myriad of the country's most significant sources of air pollution and profoundly undermine one of the Clean Air Act's basic mechanisms for protecting human health and the environment. Regardless of whether this broad exclusion is a "more natural reading" of the House amendment, EPA cannot give 111(d) a meaning that is at odds with Congressional intent. *See id.* (citing *Young v. Community Nutrition Inst.*, 476 U.S. 974, 980 (1986)). EPA cannot give effect to a reading of the House amendment that would render the Senate amendment ineffective in nearly any situation. *See United States v. Coatoam*, 245 F.3d 553, 557-58 (6th Cir. 2001) (refusing to adopt a defendant's literal reading of a statutory provision, which would have rendered another subsection surplusage in the vast majority of cases, where the government asserted that Congress made a drafting error when it amended the statute).

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[370] Both the Senate amendment and then-effective law excluded the current list of HAPs from regulation under section 111(d).

[371] The rationale for giving effect to the last provision in order of arrangement is that the last expression of the legislative will must prevail:

> [O]ne, for being earlier or later in position, must be deemed to render the other nugatory, or repeal it. The decisions are to the effect that the provision which is latest in position repeals the other. Being later in position, the prevailing provision is deemed a later expression of the legislative will. This rule and the reason for it have been criticized, because, all the provisions of an act being adopted at the same time, there is no priority in point of time on account of their relative positions in the statute. This is strictly true; but, in the reading of a bill, matter near the close may be presumed to revive the last consideration, and, if assented to, is a later conclusion.

Sutherland, Statutes and Statutory Construction (2d ed. 1904) vol. 2, § 349. This rationale applies despite the fact that the two relevant sections of the Statutes at Large amend the same statutory provision.

Newsroom

News Releases By Date

ADVISORY: Remarks by EPA Administrator Gina McCarthy at Resources for the Future

Release Date: 09/25/2014
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FOR IMMEDIATE RELEASE
September 25, 2014

ADVISORY: Remarks by EPA Administrator Gina McCarthy at Resources for the Future

As Prepared for Delivery Sept. 25, 2014

Thanks, Phil. It's great to be here at RFF. The expertise and integrity of this organization is testament to your leadership, Phil, and the passion of the people who work here.

I want to start with a story decades in the making. Forty years ago, scientists at the University of California uncovered a global crisis. Chemicals in our hairspray, refrigerators, and air conditioners were destroying our ozone layer, the Earth's protective shield against the sun's cancer-causing radiation. The world needed a solution. It needed a leader. The United States didn't temper its resolve, despite the hesitation of other nations. American science identified the problem. American industry innovated the solution.
Because we acted, the ozone layer is healing. Our people are safer. And our economy is stronger. Our fight to save the ozone layer was a defining moment in American leadership. Today, with the threat of climate change, the pollution and the problem are different, but the principle is the same. Once again, the world needs a leader. Once again, that leader must be the United States. That's the message President Obama took to the UN this week.

The President said, quote, "We cannot condemn our children to a future beyond their capacity to repair…not when we have the means…to begin repairing it right now." He's right. Climate change supercharges risks to our health and our economy. The thing is, we don't have to choose between a healthy environment and a healthy economy. They're not separate—they're intertwined. A world-leading economy depends on a healthy environment and a stable climate.

That's why under President Obama's direction, EPA proposed a Clean Power Plan to cut the harmful carbon pollution fueling climate change from our largest source, power plants. I was at the climate summit this week, and one thing is clear: U.S. climate action is changing the game. Our leadership is spurring action from government and business leaders around the world.
What's also clear, is that when it comes to climate change, the most expensive thing we could do, is to do nothing. We no longer project tomorrow's impacts, we tally up today's damages. This past decade was the hottest on record. The streets of Miami flood on sunny days. Ocean acidification threatens Washington State's oyster industry. Across the country, people grapple with floods, fires, and severe weather. Today, California is facing historic drought, with projected job losses of more than 17,000.

2012 was also the second costliest year in history for natural disasters, with a price tag of $110 billion dollars. And if we see warming of 3 degrees Celsius above pre-industrial levels, instead of 2 degrees,

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we could face additional economic damages of almost 1 percent of global output. To put that into perspective—1 percent of 2014 U.S. GDP is almost $150 billion; and we're just talking about the incremental cost of 3 degrees instead of 2. You do the math.

As seas rise, so do insurance premiums, medical bills, and food prices. From water scarcity to wilting crops, companies like General Mills and Coca-Cola see climate change as a "threat to commerce." Paying more for soda and cereal means less cash to buy other things. That chokes economies and stunts job growth.
The bottom line is: We don't act despite the economy, we act because of it.

I came to RFF because you understand the power of an economy that values clean air, clean water, and our precious natural resources. You get that climate action isn't just about polar bears and melting ice caps. It's about protecting local economies and creating jobs.

The good news is, climate action is not just a defensive play, it advances the ball. We can turn our challenge into an opportunity to modernize our power sector, and build a low-carbon economy that'll fuel growth for decades to come. That story of energy progress is being written across America.

EPA's historic fuel efficiency standards for cars and trucks are cutting pollution, saving families money at the pump, and fueling a resurgent auto industry that's added more than 250,000 jobs since 2009. Auto makers didn't fold, they flourished. Since President Obama took office, wind energy has tripled and solar has grown ten-fold. That's thousands of jobs that can't be shipped overseas. Renewable energy on public land by itself accounts for 20,000 jobs. In less than four years the average cost of solar panels has dropped over 60 percent. Every four minutes, another American home or business goes solar. And jobs in the solar industry are growing faster than any other sector in the United States.

|A study by the group Environmental Entrepreneurs shows that in the second quarter of 2014 alone, we added 12,500 clean energy jobs. America's clean energy progress is bringing down energy costs, bringing in good paying jobs, and bringing back manufacturing. An ABC poll showed that 7 in 10 Americans want us to act on climate. So do public health advocates, business groups, faith leaders, and even organized moms and grandmas.

We have over 1 million comments on our Clean Power Plan already, including some great advice from RFF. We want every good idea possible, so we extended the comment period through December 1st. People want us to act because the benefits are clear: from soot and smog reductions alone, every dollar we invest through the Clean Power Plan will return $7 dollars in health benefits. In 2030, total climate and health benefits could reach up to $93 billion dollars.

The key to making our plan ambitious and achievable is flexibility. We used section 111(d) of the Clean Air Act to allow states to choose their own low-carbon path forward. Flexibility means more choice, and more ways to invest. That sends a powerful market signal that unleashes innovation.

We want to raise the common denominator, so states that can do more learn from states that are doing more. Our plan is not a one-size-fits-all prescription, it boosts progress already underway in companies, city halls, and state capitals across the nation.

For years, states in the Northeast have teamed up in a market-based program to curb greenhouse gases. At the same time, they've enjoyed some of the nation's strongest economic growth. My home state of Massachusetts cut emissions by 40 percent, while its economy grew 7 percent. Cities and states acting on climate are not slowing down, they're speeding up. And according to a new report from the Carbon Disclosure Project, major companies like Delta, Google and Disney use an internal carbon price in their business decisions. Why? Because investors and CEO's see the cost of climate change, and the value of taking action.

We know a global problem needs a global solution. Although we can't act for other nations, when the United States of America leads, other nations follow. We set the bar for solutions. We set the pace for progress. Years ago, it was American chemical companies like DuPont and Honeywell that innovated

safer chemicals to replace the ones destroying the ozone layer, and sold those solutions to the rest of the world. And President Obama just convened a group of those companies at the White House last week, to acknowledge their commitment to slash even more pollution, and to announce administrative action that will support and speed up those efforts.

When it comes to the American economy, cutting pollution doesn't dull our competitive edge, it sharpens it. Thanks to our fuel efficiency standards, the auto industry is once again a source of economic strength. The number of cars coming off American assembly lines, made by American workers, is the highest it's been in 12 years. From catalytic converters to smoke-stack scrubbers, America has a legacy of innovating the world's leading environmental technologies—accounting for more than 1.5 million jobs and $44 billion in exports in 2008 alone. That's more than other big sectors like plastics and rubber products. If you want to talk return on investment, in over four decades, we've cut air pollution by 70 percent, while our GDP has tripled. The health and economic benefits of the 1990 Clean Air Act amendments by themselves outweigh the costs 30 to 1; Phil, I know you championed those amendments while you were in Congress.

Today we have more cars, more jobs, more businesses, and less pollution. That's how we define progress, and how we build a low-carbon economy.

So it's sad to see a small but vocal group of critics hide behind the word "economy" to protect their own special interests; when the truth is, climate action is in everyone's best interest. It's worrisome when we hear those critics say, quote, "…I'm not a scientist, but climate action is going to ruin the economy…"

Well, as President Obama has said, those critics have one thing right: they are not scientists. They're not economists, either. But guess what, we've got some pretty good ones at EPA. And at NOAA. And at NASA. We trust them to put astronauts in space, and to tell us if the air is safe for our kids to play outside. These world-renowned scientists, medical professionals, and economists like you are calling for climate action.

Simply put: the economy isn't a reason to fear action, it's a reason to take it.

A report from The New Climate Economy shows that not only is global climate action affordable, but it could actually speed up economic growth. Another recent study shows that U.S. states that are still skeptical, like Arkansas, Louisiana, Oklahoma and Texas, would actually see an annual net economic benefit of up to about $16 billion dollars. That's billion with a "b."

A surefire way to damage our economy is to neglect our need for a healthy environment to live, work, and play in. That's what's at stake. Back when we took action to heal the ozone layer, special interest critics manufactured doomsday predictions. They spun stories of supermarket refrigerators shutting off, and manufacturing plants shutting down. Guess what? None of it happened. If those scare tactics sound familiar, it's because they're the same ones we hear today on climate change.

Those same critics point fingers at other nations dragging their feet as an excuse for the United States to stand still. We don't hide behind the inaction of other nations as an excuse for mediocrity. We are not about stagnation, we are about innovation. And we don't bend to the false warnings of those who lack faith in American ingenuity, and toss aside the values that make America great. Can you imagine President Kennedy looking up at the moon and saying, "Nah...we'll just wait for someone else do it."

When we've faced challenges before, we have acted time and time again. And it's made our nation stronger. Because we acted, our kids don't grow up with acid rain or toxic leaded-gas fumes. Because we acted, we eat safer foods, drink cleaner water, and breathe cleaner air.

Because we acted, nations came together, compelled by American leadership, to save our ozone layer and protect our people. Kofi Annan called that effort the "single most successful international agreement" of any kind. Our climate challenge is not just a responsibility we should accept. It's an opportunity we should seize, to retool and resurge with new technologies, new industries, and new jobs.

Let's remind ourselves what we're capable of. Let's embrace this defining moment of American leadership. We owe it to our kids to lead on climate change. Not just to leave them a cleaner, safer planet, but an opportunity-rich economy for generations to come. Thank you.

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ENVIRONMENTAL PROTECTION AGENCY (EPA)

Statement of Priorities

OVERVIEW

For more than 40 years, the U.S. Environmental Protection Agency (EPA) has worked to protect people's health and the environment. By taking advantage of the best thinking, the newest technologies and the most cost-effective, sustainable solutions, EPA has fostered innovation and cleaned up pollution in the places where people live, work, play and learn.

With a renewed focus on the challenges ahead, science, law and transparency continue to guide EPA decisions. EPA will leverage resources with grant- and incentive-based programs, sound scientific advice, technical and compliance assistance and tools that support states, tribes, cities, towns, rural communities and the private sector in their efforts to address our shared challenges, including:

- making a visible difference in communities across the country;
- addressing climate change and improving air quality;
- taking action on toxics and chemical safety;
- protecting water: a precious, limited resource;
- launching a new era of state, tribal and local partnership; and
- working toward a sustainable future.

EPA and its federal, state, local, and community partners have made enormous progress in protecting the nation's health and environment. From reducing mercury and other toxic air pollution to reducing greenhouse gas (GHG) emissions, doubling the fuel efficiency of our cars and trucks, the Agency is working to save lives and protect the environment. In addition, while removing a billion tons of pollution from the air, the Agency has produced hundreds of billions of dollars in benefits for the American people.

HIGHLIGHTS OF EPA'S REGULATORY PLAN

EPA's more than forty years of protecting human health and the environment

demonstrates our nation's commitment to reducing pollution that can threaten the air we breathe, the water we use and the communities we live in. This Regulatory Plan contains information on some of our most important upcoming regulatory actions. As always, our Semiannual Regulatory Agenda contains information on a broader spectrum of EPA's upcoming regulatory actions.

Six Guiding Priorities

The EPA's success depends on supporting innovation and creativity in both what we do and how we do it. To guide the agency's efforts, the Agency has established several guiding priorities. These priorities are enumerated in the list that follows, along with recent progress and future objectives for each.

1. Making a Visible Difference in Communities Across the Country

Safe Disposal and Management of Coal Combustion Residuals. Coal combustion residuals (CCRs), often referred to as coal ash, are currently considered Bevill exempt wastes under the Resource Conservation and Recovery Act (RCRA). They are residues from the combustion of coal in power plants and are captured by pollution control technologies, like scrubbers. Potential environmental concerns from coal ash management include groundwater contamination from leaking surface impoundments and landfills and structural failures of surface impoundments. The need for national criteria was emphasized by the December 2008 spill of coal ash from a surface impoundment at the Tennessee Valley Authority's plant in Kingston, TN. The tragic spill flooded more than 300 acres of land with coal ash, which flowed into the Emory and Clinch rivers. On June 21, 2010, the EPA proposed to regulate for the first time coal ash to address the risks from the management of these wastes that are generated by electric utilities and independent power producers. The Agency received over 450,000 comments on the proposal. Under a consent decree, a final rule must be signed by the Administrator no later than December 19, 2014.

Environmental Justice in Rulemaking. The year 2014 represents the 20th anniversary of President Clinton's issuance of the Executive order directing all Federal agencies to engage in a Governmentwide effort and issue strategies to address environmental justice issues.

EPA has made significant progress in areas critical to advancing environmental justice and making a visible difference in communities, including rulemaking, permitting, compliance and enforcement, community-based programs and our work with other federal agencies. We have developed the critical legal, science, and

screening tools to help support our efforts in working with and in communities.

2. Addressing Climate Change and Improving Air Quality

The Agency will continue to deploy existing regulatory tools where appropriate and warranted. Addressing climate change calls for coordinated national and global efforts to reduce emissions and develop new technologies that can be deployed. Using the Clean Air Act, EPA will continue to develop greenhouse gas standards for both mobile and stationary sources.

Greenhouse Gas Emission Standards for Power Plants. As part of the President's Climate Action Plan, in September 2013, the EPA proposed standards to limit carbon pollution from new power plants yet to be built. This past June, we proposed carbon pollution standards for existing power plants, the Clean Power Plan. We plan to finalize standards for both new and existing plants in 2015. When finalized, these standards and guidelines will establish achievable limits of carbon pollution from future plants. By 2030 carbon emissions from existing plants are estimated to be reduced by 30% from 2005 levels.

Heavy-Duty Vehicles GHG Emission Standards. In 2011, in cooperation with the Department of Transportation (DOT), EPA issued the first-ever Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles for model years 2014-2018. In 2015, EPA and DOT will propose a second set of standards to further reduce greenhouse gas emissions and fuel consumption from a wide range of on-road vehicles from semi-trucks to the largest pickup trucks and vans and all types and sizes of work trucks and buses. This action is another important component of the President's Climate Action Plan.

Reviewing and Implementing Air Quality Standards. Despite progress, millions of Americans still live in areas that exceed one or more of the national air pollution standards. This year's regulatory plan describes efforts to review the primary National Ambient Air Quality Standards (NAAQS) for ozone and lead, as well as a rule to guide States in implementing the ozone, particulate matter, and other air quality standards.

Cleaner Air from Improved Technology. EPA continues to address hazardous air pollution under authority of the Clean Air Act Amendments of 1990. The centerpiece of this effort is the "Maximum Achievable Control Technology" (MACT) program, which requires that all major sources of a given type use emission controls that better reflect the current state of the art. In May of 2015, EPA

expects to complete a review of existing MACT standards for Petroleum Refineries to reduce residual risk and assure that the standards reflect current technology.

3. Taking Action on Toxics and Chemical Safety

One of EPA's highest priorities is to make significant progress in assuring the safety of chemicals. Using sound science as a compass, EPA protects individuals, families, and the environment from potential risks of pesticides and other chemicals. In its implementation of these programs, EPA uses several different statutory authorities, including the Federal Insecticide, Fungicide and Rodenticide Act (FIFRA), the Federal Food, Drug and Cosmetic Act (FFDCA), the Toxic Substances Control Act (TSCA) and the Pollution Prevention Act (PPA), as well as collaborative and voluntary activities. In FY 2014, the Agency will continue to satisfy its overall directives under these authorities and highlights the following actions in this Regulatory Plan:

EPA's Existing Chemicals Management Program Under TSCA. As part of EPA's ongoing efforts to ensure the safety of chemicals, EPA plans to take a range of identified regulatory actions for certain chemicals and assess other chemicals to determine if risk reduction action is needed to address potential concerns.

Addressing Formaldehyde Used in Composite Wood Products. As directed by the Formaldehyde Standards for Composite Wood Products Act of 2010, EPA is developing final regulations to address formaldehyde emissions from hardwood plywood, particleboard and medium-density fiberboard that is sold, supplied, offered for sale, or manufactured in the United States.

Lead in Public and Commercial Buildings. As directed by TSCA section 402(c)(3), EPA is developing a proposed rule to address renovation or remodeling activities that create lead-based paint hazards in pre-1978 public buildings and commercial buildings. EPA previously issued a final rule to address lead-based paint hazards created by these activities in target housing and child-occupied facilities.

Reassessment of PCB Use Authorizations. When enacted in 1978, TSCA banned the manufacture, processing, distribution in commerce, and use of polychlorinated biphenyls (PCBs), except when uses would pose no unreasonable risk of injury to health or the environment. EPA is reassessing certain ongoing, authorized uses of PCBs that were established by regulation in 1979, including the use, distribution in commerce, marking and storage for reuse of liquid PCBs in electric equipment, to

determine whether those authorized uses still meet TSCA's "no unreasonable risk" standard. EPA plans to propose the revocation or revision of any PCBs use authorizations included in this reassessment that no longer meet the TSCA standard.

Enhancing Agricultural Worker Protection. Based on years of extensive stakeholder engagement and public meetings, EPA is acting to enhance the pesticide worker safety program. EPA plans to issue final amendments to the agricultural worker protection regulation that strengthens protections for agricultural farm workers and pesticide handlers. The rule is expected improve pesticide safety training and agricultural workers' ability to protect themselves and their families from potential secondary exposure to pesticides and pesticide residues. The proposed revisions will address key environmental justice concerns for a population that may be disproportionately affected by pesticide exposure. Other changes under development are intended to bring hazard communication requirements more in line with Occupational Safety and Health Administration requirements and seek to clarify current requirements to facilitate program implementation and enforcement.

Strengthening Pesticide Applicator Safety. As part of EPA's effort to enhance the pesticide worker safety program, the Agency is also developing a proposal to revise the existing regulation concerning the certification of applicators of restricted-use pesticides to ensure that the federal certification program standards adequately protect applicators, the public and the environment from potential risks associated with use of restricted use pesticides. The proposed changes are intended to improve the competency of certified applicators of restricted use pesticides, increase protection for noncertified applicators of restricted use pesticides operating under the direct supervision of a certified applicator through enhanced pesticide safety training and standards for supervision of noncertified applicators, and establish a minimum age requirement for such noncertified applicators. Also, in keeping with EPA's commitment to work more closely with tribal governments to strengthen environmental protection in Indian Country, certain changes are intended to provide more practical options for establishing certification programs in Indian Country.

Improving Chemical Facility Safety and Security. Executive Order 13650 on Improving Chemical Facility Safety and Security directs federal agencies to work with stakeholders to improve chemical safety and security through agency programs, private sector initiatives, federal guidance, standards, and regulations. During the course of implementing this Executive order, EPA, along with the Department of Homeland Security (including the National Protection and Programs Directorate, the Transportation Security Agency and the United States Coast Guard); the Occupational Safety and Health Administration; the United States

Department of Justice, Bureau of Alcohol, Tobacco, and Firearms; the United States Department of Agriculture; and the United States Department of Transportation, will assess whether its regulations should be modified or new regulations developed to improve upon chemical safety and security. EPA issued in July 2014 a request for information on how to strengthen its Risk Management Plan program. EPA plans to develop a proposed rule to modernize the Risk Management Plan.

4. Protecting Water: A Precious, Limited Resource

Despite considerable progress, America's waters remain imperiled. Water quality protection programs face complex challenges, from nutrient loadings and stormwater runoff to invasive species and drinking water contaminants. These challenges demand both traditional and innovative strategies.

Improving Water Quality. EPA plans to address challenging water quality issues in several rulemakings during FY 2015.

Definition of "Waters of the United States" Under the Clean Water Act. After U.S. Supreme Court decisions in SWANCC and Rapanos, the scope of "waters of the US" protected under Clean Water Act (CWA) programs has been an issue of considerable debate and uncertainty. The Act does not distinguish among programs as to what constitutes "waters of the United States." As a result, these decisions affect the geographic scope of all CWA programs. SWANCC and Rapanos did not invalidate the current regulatory definition of "waters of the United States." However, the decisions established important considerations for how those regulations should be interpreted. Experience implementing the regulations following the two court cases has identified several areas that could benefit from additional clarification through rulemaking.

Steam Electric Power Plants. Steam electric power plants contribute over half of all toxic pollutants discharged to surface waters by all industrial categories currently regulated in the United States under the Clean Water Act. Discharges of these toxic pollutants are linked to cancer and neurological damage in humans and ecological damage. EPA will establish national technology-based regulations called effluent guidelines to reduce discharges of these pollutants from industries to waters of the U.S. and publicly owned treatment works. These guidelines would set the first Federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the industry over the last three decades. The steam electric effluent guidelines apply to steam electric power plants using nuclear or fossil fuels, such as coal, oil and natural gas.

Water Quality Standards Regulatory Revisions. EPA will finalize updates to the Water Quality Standards regulation, which provides a strong foundation for water quality-based controls, including water quality assessments, impaired waters lists, total maximum daily loads, and water quality-based effluent limits (WQBELs) in NPDES discharge permits. These updates aim to clarify and resolve a number of policy and technical issues that have recurred over the past 30 years. They will assure greater public transparency, better stakeholder information, and more effective implementation of the Water Quality Standards program.

Responding to Oil Spills in U.S. Waters. The Clean Water Act (CWA), as amended by the Oil Pollution Act (OPA), requires that the National Contingency Plan (NCP) include a schedule identifying "dispersants, other chemicals, and other spill mitigating devices and substances, if any, that may be used in carrying out" the NCP. EPA is considering amending subpart J of the NCP (the Product Schedule) for a manufacturer to have chemical, biological, or other spill-mitigating substances listed on the Product Schedule, updating the listing requirements to reflect new advancements in scientific understanding, and, to the extent practicable, considering and addressing concerns regarding the use of dispersants raised during the Deepwater Horizon oil spill.

5. Launching a New Era of State, Tribal and Local Partnership

EPA's success depends more than ever on working with increasingly capable and environmentally conscious partners. States have demonstrated leadership on managing environmental challenges, and EPA wants to build on and complement their work. EPA supports state and tribal capacity to ensure that programs are consistently delivered nationwide. This provides EPA and its intergovernmental partners with an opportunity to further strengthen their working relationship and, thereby, more effectively pursue their shared goal of national environmental and public health protection. The history and future of environmental protection will be built on this type of collaboration.

In July 2014, EPA's Administrator Gina McCarthy signed the Environmental Justice Policy for Working with Tribes and Indigenous Peoples, reinforcing the agency's commitment to work with tribes on a government-to-government basis when issues of environmental justice arise. This policy allows EPA to reinforce its commitment to tribal communities, especially in addressing issues of environmental justice. The policy integrates 17 environmental justice and civil rights principles and identifies existing informational and resource tools to support EPA in addressing environmental justice concerns raised by Federally Recognized Tribes and

Indigenous Peoples throughout the United States.

In addition, 2014 marks 30 years of EPA's 1984 Indian Policy. EPA was the first to formally adopt such a Policy, reiterating the importance of EPA's tribal programs and our unique government-to-government relationship with tribes.

6. Working Toward a Sustainable Future

Just as today's economy is vastly different from that of 40 years before, EPA's regulatory program is evolving to recognize the progress that has already been made in environmental protection and to incorporate new technologies and approaches that allow us to provide for an environmentally sustainable future more efficiently and effectively.

Establishing User Fees for the Use of RCRA Manifests. The e-Manifest Final rule of February 7, 2014 codified certain provisions of the "Hazardous Waste Electronic Manifest Establishment Act" (or the Act), which directed EPA to adopt a regulation that authorized the use of electronic manifests to track hazardous waste shipments nationwide. The Act also instructed EPA to develop a user-fee-funded e-Manifest system. Since the Act grants broad discretion to EPA to determine the fees and gives the Agency authority to collect such fees for both electronic manifests and any paper manifests that continue in use, EPA plans to issue rulemaking to establish the appropriate electronic and paper manifest fees. The initial fees established in the final rule are expected to cover the operation and maintenance costs for the system, as well as the costs associated with the development of the system. EPA plans to also announce in the final rule the date on which the system will be implemented and available to users.

Once the national e-Manifest system becomes available, hazardous waste handlers will be able to complete, sign, transmit, and store electronic manifests through the national IT system, or they can elect to continue tracking the hazardous waste under the paper manifest system. Further, waste handlers that currently submit manifests to the States will no longer be required to do so, unless required by the State, as EPA will collect both the remaining paper manifest copies and electronic manifests in the national system and will disseminate the manifest data to those States that want it.

Strengthening the Underground Storage Tanks Program. EPA plans to revise the 1988 federal underground storage tank (UST) regulations by increasing emphasis on properly operating and maintaining UST equipment. These revisions

will help improve prevention and detection of UST releases, which are one of the leading sources of groundwater contamination. The revisions will also help ensure all USTs in the United States, including those in Indian country, meet the same minimum standards.

Retrospective Review of Existing Regulations

Pursuant to section 6 of Executive Order 13563 "Improving Regulation and Regulatory Review" (Jan. 18, 2011), the following Regulatory Identifier Numbers (RINs) have been identified as associated with retrospective review and analysis in the Agency's final retrospective review of regulations plan. Some of these entries on this list may be completed actions, which do not appear in *The Regulatory Plan*. However, more information can be found about these completed rulemakings in past publications of the Unified Agenda on Reginfo.gov in the Completed Actions section for that agency. These rulemakings can also be found on Regulations.gov. EPA's final agency plan can be found at: http://www.epa.gov/regdarrt/retrospective/.

Regulatory Identifier Number (RIN)	**Rulemaking Title**
2060-AO60	New Source Performance Standards (NSPS) Review under CAA -111(b)(1)(B)
2060-AP06	New Source Performance Standards for Grain Elevators - Amendments
2040-AF15	National Primary Drinking Water Regulations for Lead and Copper: Regulatory Revisions
2040-AF16	Water Quality Standards Regulatory Clarifications
2040-AF25	National Pollutant Discharge Elimination System (NPDES) Application and Program Updates Rule
2040-AF29	National Primary Drinking Water Regulations: Group Regulation of Carcinogenic Volatile Organic Compound (VOCs)
2050-AG39	Management Standards for Hazardous Waste Pharmaceuticals
2050-AG72	Hazardous Waste Requirements for Retail Products; Clarifying and Making the Program More Effective
2070-AK02	Lead; Lead-based Paint Program; Amendment to Jurisdiction-Specific Certification and Accreditation Requirements and Renovator Refresher Training Requirements

Burden Reduction

As described above, EPA continues to review its existing regulations in an effort to achieve its mission in the most efficient means possible. To this end, the Agency is committed to identifying areas in its regulatory program where significant savings or quantifiable reductions in paperwork burdens might be achieved, as outlined in Executive Order 13610, while protecting public health and our environment.

Rules Expected to Affect Small Entities

By better coordinating small business activities, EPA aims to improve its technical assistance and outreach efforts, minimize burdens to small businesses in its regulations, and simplify small businesses' participation in its voluntary programs. Actions that may affect small entities can be tracked on EPA's Regulatory Development and Retrospective Review Tracker (http://www.epa.gov/regdarrt/) at any time. This Plan includes the following rules that may be of particular interest to small entities:

Regulatory Identifier Number (RIN)	**Rulemaking Title**
2070-AJ92	Formaldehyde Emission Standards for Composite Wood Products
2060-AS16	Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles - Phase 2

International Regulatory Cooperation Activities

EPA has considered international regulatory cooperation activities as described in Executive Order 13609 and has identified two international activities that are anticipated to lead to significant regulations in the following year:

Regulatory Identifier Number (RIN)	**Rulemaking Title**
2070-AJ44	Formaldehyde; Third-Party Certification Framework for the Formaldehyde Standards for Composite Wood Products
2070-AJ92	Formaldehyde Emission Standards for Composite Wood Products

Streamlining the Export/Import Process for America's Businesses

EPA has considered import and export streamlining activities as described in Executive Order 13659 and identified the following rulemaking activity:

Regulatory Identifier Number (RIN)	**Rulemaking Title**
2050-AG77	Hazardous Waste Export-Import Revisions Rule

EPA FACT SHEET: Clean Power Plan and Carbon Pollution Standards

KEY DATES

CUTTING CARBON POLLUTION FROM POWER PLANTS

The U.S. Environmental Protection Agency, under President Obama's Climate Action Plan, has been working on a commonsense approach to cut carbon pollution from power plants. The science shows that climate change is already posing risks to our health and our economy. The Clean Power Plan for Existing Power Plants and the Carbon Pollution Standards for New Power Plants will maintain an affordable, reliable energy system, while cutting pollution and protecting our health and environment now and for future generations.

The following list provides key dates from EPA's proposals and planned dates for proposing and finalizing Clean Air Act standards and actions to address carbon pollution from existing, new, modified and reconstructed power plants:

Previous Milestones

- **Carbon Pollution Standards for new power plants**
  Clean Air Act Section 111(b)
  - September 20, 2013 – EPA announces proposed standards to limit carbon pollution from new power plants.
  - January 8, 2014 –Proposal publishes in Federal Register and 60-day comment period begins.
  - February 5, 2014 – EPA issues Notice of Data Availability.
  - February 26, 2014 -- EPA extends comment period by 60 days.
  - May 9, 2014 – 120-day comment period closes. EPA receives roughly 2 million comments.

- **Clean Power Plan for existing power plants**
  Clean Air Act Section 111(d)
  - June 2, 2014 – EPA announces proposed Clean Power Plan to limit carbon pollution from existing power plants in States.
  - June 18, 2014 – Proposal publishes in Federal Register and 120-day public comment period begins.
  - September 18, 2014 – EPA extends comment period by 45 days.
  - October 28, 2014 – EPA issues Notice of Data Availability.
  - December 1, 2014 – 165-day comment period ends. EPA receives more than 2 million public comments.

- **Clean Power Plan for existing power plants – supplemental proposal**
  Clean Air Act Section 111(d)
  - October 28, 2014 – EPA announces proposed Clean Power Plan to limit carbon pollution from existing power plants in Indian Country and U.S. Territories.

- November 4, 2014 – Supplemental proposal publishes in Federal Register and 45-day public comment period begins.
- December 19, 2014 – Comment period closes.

- **Carbon Pollution Standards for modified and reconstructed power plants**
  Clean Air Act Section 111(b)
  - June 2, 2014 – EPA announces proposed standards to limit carbon pollution from modified and reconstructed power plants.
  - June 18, 2014 – Proposal publishes in Federal Register and 120-day public comment period begins.
  - October 16, 2014 – 120-day comment period closes. EPA receives about 235 public comments.

Upcoming Milestones

- January 2015
  - EPA to begin the regulatory process for proposing a federal plan to meet goals for cutting carbon pollution from existing power plants.

- Summer 2015
  - EPA to issue **final rules** on:
    - Clean Power Plan for **Existing Power Plants** in States, Indian Country and U.S. Territories.
    - Carbon Pollution Standards for **New, Modified and Reconstructed Power Plants.**
  - EPA plans to **propose a federal plan** for meeting Clean Power Plan goals for public review and comment.

- Summer 2016
  - Proposed due date for states to **submit compliance plans** to EPA – these can be complete plans or initial plans with requests for 1- or 2-year extensions.
  - EPA will be in a position to issue a **final federal plan** for meeting Clean Power Plan goals in areas that do not submit plans.

- Summer 2017
  - Proposed due date for compliance plans with 1-year extension.

- Summer 2018
  - Proposed due date for multi-state compliance plans with 2-year extension.

- Summer 2020
  - Proposed beginning of the Clean Power Plan **compliance period**.

INVESTING IN AMERICA'S FUTURE

"We have to make our economy work for every working American. And every policy I pursue as President is aimed at answering that challenge."

—President Barack Obama, Northwestern University, October 2, 2014

Today in America, we are seeing real, tangible evidence of economic recovery from the crisis the President inherited. In a 58-month streak, the longest on record, American businesses have created more than 11 million new jobs, and almost all of the employment gains since 2010 have been in full-time positions. All in all, the economy added more jobs in 2014 than in any year since the 1990s.

The Administration's investments in American manufacturing have helped fuel its best stretch of job growth since the 1990s. America is now the number-one producer of oil and the number-one producer of natural gas; this has meant decreasing dependence on imported oil and increasing competitiveness for American industry. The rescue of the auto industry officially ended in December 2014, and the American auto industry is on track for its strongest year of new vehicle production since 2005; about half a million new jobs have been created in auto production and sales since mid-2009, when Chrysler and General Motors emerged from bankruptcy.

Since the President took office, the deficit has been cut by about two thirds. The Nation has seen the slowest health care cost growth in 50 years, with the largest reduction in the number of uninsured Americans in decades. The high school graduation rate is above 80 percent for the first time in history. Both the crime rate and the incarceration rate are falling.

We now have the chance to make sure that all Americans are able to benefit from the economic recovery. America's promise has always been that if we work hard, we can change our circumstances for the better. The economy cannot truly succeed until we live up to that promise. The Budget lays out a strategy to reach that promise, by investing in the drivers of growth and opportunity for all Americans.

To ensure America remains a magnet for jobs, the Budget builds on investments in manufacturing and innovation—including through clean energy technology programs and tax policies that position America as a global clean energy leader with a strong and modern energy infrastructure. To fix the Nation's roads and bridges and create more middle class jobs, it continues the progress toward building a 21st Century infrastructure. The Budget invests in education and job training to give American workers the skills they need to compete in the global economy. It also provides resources to programs that help create opportunity and economic mobility for all, and it reforms the tax system to better support and reward work.

To further the progress made to prevent another crisis such as the one we saw in 2008, the

gas emissions were projected to continue increasing indefinitely, but the President set a new course with an ambitious goal to cut emissions in the range of 17 percent below 2005 levels in 2020. Throughout the first term, the Administration took strong actions to cut carbon pollution, including investing more than $80 billion in clean energy technologies through the Recovery Act, establishing historic fuel economy standards, supporting policies that contributed to a doubling of renewable energy generation, and implementing ambitious energy efficiency measures.

In 2013, the President launched an ambitious Climate Action Plan that built on the progress during the first term and doubled-down on cutting carbon pollution, preparing the Nation for climate impacts, and leading internationally. The Plan puts the Nation on track to meet the President's 2020 goal and establishes a strong foundation to reach the new 2025 goal by cutting carbon pollution through new measures, including a Clean Power Plan, historic standards for heavy-duty engines and vehicles, new energy efficiency standards, and economy-wide measures to reduce other greenhouse gases.

Cutting Carbon Pollution. Cutting carbon pollution is essential to reducing the threat of climate change and represents one of the greatest economic opportunities of the 21st Century. Investments in pollution-cutting technologies and proven energy efficiency and clean energy solutions are investments in American jobs, American industries, and Americans' health.

That is why in June 2014, the EPA proposed the Clean Power Plan, a flexible, commonsense approach that builds on the actions States, cities, and businesses across the United States are already taking to address the risks of climate change by reducing carbon pollution from existing power plants.

The Budget includes $239 million to support EPA efforts to address climate change through commonsense standards, guidelines, and voluntary programs, including $25 million to help States develop their Clean Power Plan strategies.

The Budget also includes an incentive fund for States choosing to go beyond the Clean Power Plan, which will be finalized this summer. The Clean Power State Incentive Fund will provide $4 billion to support States exceeding the minimum requirements established in the Clean Power Plan for timing of State plans and the pace and extent of carbon pollution reductions from the power sector. This funding will enable States to invest in a range of activities that complement and advance the Clean Power Plan, including efforts to address disproportionate impacts from environmental pollution in low-income communities and support for businesses to expand efforts in energy efficiency, renewable energy, and combined heat and power through, for example, grants and investments in much-needed infrastructure.

To support the development of pollution-cutting technologies, the Budget invests approximately $7.4 billion in clean energy technology programs, advancing American clean energy leadership, supporting job creation, and increasing energy security. These programs conduct research, development, and deployment efforts that stimulate the evolution and use of clean energy sources such as solar, wind, and low-carbon fossil fuels, as well as energy-efficient technologies, products, and process improvements. The largest investors are DOE, the Department of Defense (DOD), NSF, and USDA. DOE provides about 75 percent of the clean energy technology funding and supports a wide array of efforts across the clean energy spectrum that will further reduce costs and increase the use of clean energy technologies. For example, these efforts include increasing the affordability and convenience of advanced vehicles and domestic renewable fuels. They will advance technologies to improve the efficiency of the residential and commercial buildings of today and tomorrow, making energy systems more easily integrated into the electric grid. DOE is also developing technologies that reduce the costs of carbon capture from fossil fuels, undertaking research to ensure the safe, permanent storage of carbon dioxide in underground geologic formations, and conducting R&D to measure and mitigate fugitive methane emissions from natural gas infrastructure. DOE is also supporting