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WHO: Sponsored by the Office of the Federal Register.

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WHY: To provide the public with access to information necessary to research Federal agency regulations which directly affect them. There will be no discussion of specific agency regulations.

WHEN: Tuesday, March 13, 2012
9 a.m.–12:30 p.m.

WHERE: Office of the Federal Register
Conference Room, Suite 700
800 North Capitol Street, NW.
Washington, DC 20002

RESERVATIONS: (202) 741-6008

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Reader Aids

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CFR PARTS AFFECTED IN THIS ISSUE

A cumulative list of the parts affected this month can be found in the Reader Aids section at the end of this issue.

Rules and Regulations

Federal Register

Vol. 77, No. 32

Thursday, February 16, 2012

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 1

[Docket No. FAA–2012–0019; Amdt. No. 1–67]

RIN 2120–AK03

Removal of Category IIIa, IIIb, and IIIc Definitions

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Direct final rule; request for comments.

SUMMARY: The FAA is removing the definitions of Category IIIa, IIIb, and IIIc operations. The definitions are outdated because they are no longer used for aircraft certification or operational authorization. Removing the definitions will aid in international harmonization efforts, future landing minima reductions, and airspace system capacity improvements due to the implementation of performance based operations.

DATES: Effective April 16, 2012.

Submit comments on or before March 19, 2012. If adverse comment is received, the FAA will publish a timely withdrawal in the **Federal Register**.

ADDRESSES: You may send comments identified by docket number FAA–2012–0019 using any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov* and follow the online instructions for sending your comments electronically.
- *Mail:* Send comments to Docket Operations, M–30; U.S. Department of Transportation (DOT), 1200 New Jersey Avenue SE., Room W12–140, West Building Ground Floor, Washington, DC 20590–0001.
- *Hand Delivery or Courier:* Take comments to Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.
- *Fax:* Fax comments to Docket Operations at 202–493–2251.

Privacy: The FAA will post all comments it receives, without change, to *http://www.regulations.gov*, including any personal information the commenter provides. Using the search function of the docket web site, anyone can find and read the electronic form of all comments received into any FAA docket, including the name of the individual sending the comment (or signing the comment for an association, business, labor union, etc.). DOT's complete Privacy Act Statement can be found in the **Federal Register** published on April 11, 2000 (65 FR 19477–19478), as well as at *http://DocketsInfo.dot.gov*.

Docket: Background documents or comments received may be read at *http://www.regulations.gov* at any time. Follow the online instructions for accessing the docket or go to Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: For technical questions concerning this action, contact Bryant Welch, Flight Technologies and Procedures Division, Flight Operations Branch, AFS–410, Federal Aviation Administration, 470 L'Enfant Plaza, Suite 4102, Washington, DC 20024; telephone (202) 385–4539; email *bryant.welch@faa.gov*.

For legal questions concerning this action, contact Nancy Sanchez, Office of the Chief Counsel, Regulations Division, AGC–200, Federal Aviation Administration, 800 Independence Avenue SW., Washington, DC 20591; telephone (202) 267–3073; email *nancy.sanchez@faa.gov.*

SUPPLEMENTARY INFORMATION:

Authority for This Rulemaking

The FAA's authority to issue rules on aviation safety is found in Title 49 of the United States Code. Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority.

This rulemaking is promulgated under the authority described in 49 U.S.C. 40103, which vests the Administrator with broad authority to prescribe regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace, and 49 U.S.C. 44701(a)(5), which requires the Administrator to promulgate regulations and minimum standards for other practices, methods, and procedures necessary for safety in air commerce and national security.

The Direct Final Rule Procedure

The FAA is adopting this direct final rule without prior notice and prior public comment because this rule is not controversial, is not expected to result in the receipt of an adverse comment, and a notice of proposed rulemaking (NPRM) is not necessary. The Category IIIa, IIIb, and IIIc operations definitions are outdated, unnecessary, and overly restrictive. The FAA does not believe we will receive an adverse comment because this rule will not affect any existing operator's aircraft certification or operational approval. The Regulatory Policies and Procedures of the Department of Transportation (DOT) (44 FR 1134) provide that to the maximum extent possible, operating administrations for the DOT should provide an opportunity for public comment on regulations issued without prior notice. Accordingly, the FAA invites interested persons to participate in this rulemaking by submitting written comments, data, or views. The agency also invites comments relating to the economic, environmental, energy, or federalism impacts that might result from adopting this final rule.

Unless a written adverse or negative comment or a written notice of intent to submit an adverse or negative comment is received within the comment period, the regulation will become effective on the date specified above. After the close of the comment period, the FAA will publish a document in the **Federal Register** indicating that no adverse or negative comments were received and confirming the date on which the final rule will become effective. If the FAA does receive, within the comment period, an adverse or negative comment, or written notice of intent to submit such a comment, a document withdrawing the direct final rule will be published in the **Federal Register**, and an NPRM may be published with a new comment period.

See the ''Additional Information'' section for information on how to comment on this direct final rule and how the FAA will handle comments received. In addition, there is information on obtaining copies of rulemaking documents.

I. Overview of Final Rule

The FAA is removing the definitions of Category IIIa, IIIb, and IIIc operations. Category III aircraft operations are precision approach and landing operations using an Instrument Landing System (ILS) conducted in very low visibility conditions. Currently, any approach and landing with a runway visual range (RVR) below 1000 feet is considered a Category III operation.[1] The Category IIIa, IIIb, and IIIc operations definitions divide the general regime of Category III operations into specific RVR (visibility) bands. The definitions are outdated because they are no longer used for aircraft certification or operational authorization. Removing the Category IIIa, IIIb, and IIIc operations definitions will have no effect on existing Category III operators. The general Category III operation definition remains in effect, and is fully described in FAA orders and advisory circulars.

II. Discussion of the Direct Final Rule

History

The International Civil Aviation Organization (ICAO) established the general concepts and definition of Category III operations in 1966 in ICAO Annex 10, *Aeronautical Communications* and then added the definitions of Category IIIa, IIIb, and IIIc operations in 1967. These did not correspond exactly with current definitions, but the required RVR values are the same. The FAA issued the initial U.S. CAT IIIa criteria (Advisory Circular (AC) 120–28, Criteria for Approval of Category III Weather Minima for Takeoff, Landing, and Rollout) on September 5, 1969, to assist industry in developing a CAT IIIa (minimum RVR 700 feet) approach capability. These criteria included the basic concepts and minimum airborne equipment design requirements necessary for Category III operations, including the Fail Operational and Fail Passive control system concepts.[2] The first U.S. aircraft certification for CAT IIIa occurred in 1971. This approval was based on the use of Fail Operational automatic landing systems.

In December 1971, the FAA revised the CAT IIIa criteria (AC 120–28A) by establishing initial operational approval criteria. These criteria were based on a conservative approach for reducing operating minima. However, as industry gained operational experience, the FAA determined that the AC 120–28A criteria were unnecessarily stringent. In December 1976, the U.S. certificated the first airplane for Fail Passive CAT IIIa operations. This and following certifications were based on the use of Fail Operational or Fail Passive flight control systems, but some Aircraft Flight Manuals specified that the aircraft were suitable for Category IIIa operations.

As operational experience and the capabilities of airborne equipment increased in CAT IIIa operations, the FAA and industry realized the need for CAT IIIb (RVR lower than 700 feet but no lower than 150 feet) criteria. The FAA issued the initial U.S. CAT IIIb criteria for RVR 600 operations in March 1984 (AC 120–28C). Aircraft certifications and operational approvals continued to be based on the capabilities of the aircraft's Fail Operational or Fail Passive flight control systems, but also continued to tie the certifications and approvals to the Category IIIa and IIIb definitions. CAT IIIc operations are conducted with RVR below 150 feet. The FAA has not developed the criteria for aircraft certification and operational approval for Category IIIc operations. Therefore, Category IIIc operations have not been authorized.

The FAA codified the definitions of Category IIIa, IIIb, and IIIc operations in 1996. ICAO adopted the same definitions in ICAO Annex 6, *Operation of Aircraft,* in 1998. These definitions described the operational concepts in use at that time, and reflected existing technological capabilities and operational requirements. The definitions were used in certification and authorization documents. However, advances in aircraft technology and changes in the framework of operational approval have rendered the definitions obsolete for those purposes. While still used for discussion and as a shorthand way to describe different levels of Category III operations, the Category IIIa, IIIb, and IIIc definitions are no longer used as a basis for aircraft certification or for issuance of operational authorizations.

Domestic Practice

While AC 120–28D, issued in October 1999, references the definitions of Category IIIa, IIIb, and IIIc operations, the aircraft certification and operational approval documentation no longer uses these definitions. Under AC 120–28D, aircraft certifications are based solely on the demonstrated capabilities of the aircraft to land and rollout on the runway. For example, an aircraft with Fail Operational systems may be demonstrated to automatically land and rollout at RVR 150 feet, and this capability is stated in the Aircraft Flight Manual. The operational approvals will be based on that Manual without reference to the Category IIIa, IIIb, and IIIc definitions.

International Practice

An effort is underway to rationalize and standardize Category III approach minima internationally. Aircraft certification standards are essentially the same worldwide with regard to the use of Fail Operational or Fail Passive system criteria to describe landing capabilities. Operational approval criteria are also based on the aircraft system capabilities, as in the United States. However, the publication of Category III landing minima for use on the approach are still tied to the Category IIIa, IIIb, and IIIc definitions, both internationally and in the United States. The FAA is removing the CAT IIIa, IIIb, and IIIc definitions as a first step toward the universal description of Category III operations and certification in terms currently used. The FAA presented a Working Paper to the ICAO Operations Council in October, 2011 requesting the deletion of the Category IIIa, IIIb, and IIIc definitions from the ICAO Annexes. The FAA also presented a similar paper to the European Aviation Safety Agency (EASA)/FAA All Weather Operations Harmonization Working Group in October, 2011.

Landing Minima

Category III approach charts depicting landing minima in terms of the Category IIIa, IIIb, and IIIc definitions are now unnecessary. The Category III landing minima at a particular runway are based on the demonstrated qualities and capabilities of the ILS installed on that runway. The FAA tests every installed ILS in accordance with ICAO criteria,

[1] Category III operational approvals and instrument procedures are described in terms of RVR. RVR is an instrumentally derived value, given in feet, that reflects seeing conditions on a runway, and is dependent on the use of high intensity runway lighting.

[2] Fail Operational means an airborne system with redundant operational capability down to touchdown and, if applicable, through rollout. Fail Passive means an automatic flight control system, which, upon occurrence of any single failure, should not cause: Significant displacement from the approach path, altitude loss, or significant out of trim condition.

and the results are classified and published to define the allowable landing minima. These ILS classifications are used directly in the determination of landing minima.

Once this rule is effective, the FAA will amend FAA Orders defining publication of Category III minima by removing references to Category IIIa, IIIb, and IIIc operations. The amended Orders will directly relate the ILS system classification to the allowable published minima. The approach charts will show only the lowest possible Category III landing minima on a runway. For example, the approach chart for a landing at an airport would only state that the RVR is 600 and will not make any reference to the CAT IIIb operations definition. Operators will use the published minima in conjunction with their Operations Specifications to determine the lowest landing minima allowed to them, as is currently done.

Impact on Future Operations

Future Category III operations may derive from new low visibility approach and landing technologies. The type of operations, landing minima and aircraft certification criteria for these future systems will not follow the Category IIIa, IIIb, and IIIc definitions. Thus, removing the Category IIIa, IIIb, and IIIc definitions will eliminate the need for future systems to comply with these outdated definitions.

III. Regulatory Notices and Analyses

A. Regulatory Evaluation

Changes to Federal regulations must undergo several economic analyses. First, Executive Order 12866 and Executive Order 13563 direct that each Federal agency shall propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs. Second, the Regulatory Flexibility Act of 1980 (Pub. L. 96–354) requires agencies to analyze the economic impact of regulatory changes on small entities. Third, the Trade Agreements Act (Pub. L. 96–39) prohibits agencies from setting standards that create unnecessary obstacles to the foreign commerce of the United States. In developing U.S. standards, the Trade Act requires agencies to consider international standards and, where appropriate, that they be the basis of U.S. standards. Fourth, the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) requires agencies to prepare a written assessment of the costs, benefits, and other effects of proposed or final rules that include a Federal mandate likely to result in the expenditure by State, local, or tribal governments, in the aggregate, or by the private sector, of $100 million or more annually (adjusted for inflation with base year of 1995). This portion of the preamble summarizes the FAA's analysis of the economic impacts of this final rule.

Department of Transportation Order DOT 2100.5 prescribes policies and procedures for simplification, analysis, and review of regulations. If the expected cost impact is so minimal that a proposed or final rule does not warrant a full evaluation, this order permits that a statement to that effect and the basis for it be included in the preamble if a full regulatory evaluation of the cost and benefits is not prepared. Such a determination has been made for this final rule.

The FAA is removing the definitions of Category IIIa, IIIb, and IIIc operations. Since this final rule removes outdated and unnecessary definitions, the expected outcome will be a minimal impact with positive net benefits, and a regulatory evaluation was not prepared. The FAA requests comments with supporting justification about the FAA determination of minimal impact.

The FAA has, therefore, determined that this final rule is not a ''significant regulatory action'' as defined in section 3(f) of Executive Order 12866, and is not ''significant'' as defined in DOT's Regulatory Policies and Procedures.

B. Regulatory Flexibility Determination

The Regulatory Flexibility Act of 1980 (Pub. L. 96–354) (RFA) establishes ''as a principle of regulatory issuance that agencies shall endeavor, consistent with the objectives of the rule and of applicable statutes, to fit regulatory and informational requirements to the scale of the businesses, organizations, and governmental jurisdictions subject to regulation. To achieve this principle, agencies are required to solicit and consider flexible regulatory proposals and to explain the rationale for their actions to assure that such proposals are given serious consideration.'' The RFA covers a wide-range of small entities, including small businesses, not-for-profit organizations, and small governmental jurisdictions.

Agencies must perform a review to determine whether a rule will have a significant economic impact on a substantial number of small entities. If the agency determines that it will, the agency must prepare a regulatory flexibility analysis as described in the RFA. However, if any agency determines that a rule is not expected to have a significant economic impact on a substantial number of entities, section 605(b) of RFA provides that the head of the agency may so certify and a regulatory flexibility analysis is not required. The certification must include a statement providing the factual basis for this determination, and the reasoning should be clear.

As noted above, the changes to § 1.1 are cost relieving because the FAA is removing the definitions of Category IIIa, IIIb, and IIIc operations. The definitions are outdated and no longer used for aircraft certification or operational authorization. Therefore, as the FAA Acting Administrator, I certify that this rule will not have a significant economic impact on a substantial number of small entities.

C. International Trade Impact Assessment

The Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. Pursuant to these Acts, the establishment of standards is not considered an unnecessary obstacle to the foreign commerce of the United States, so long as the standard has a legitimate domestic objective, such as the protection of safety, and does not operate in a manner that excludes imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards. The FAA has assessed the potential effect of this final rule and determined that it is neither considered an unnecessary obstacle nor a promotion to international trade and therefore it will have no impact on international trade.

D. Unfunded Mandates Assessment

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) requires each Federal agency to prepare a written statement assessing the effects of any Federal mandate in a proposed or final agency rule that may result in an expenditure of $100 million or more (in 1995 dollars) in any one year by State, local, and tribal governments, in the aggregate, or by the private sector; such a mandate is deemed to be a ''significant regulatory action.'' The FAA currently uses an inflation-adjusted value of $143.1 million in lieu of $100 million. This final rule does not contain such a mandate; therefore, the requirements of Title II of the Act do not apply.

E. Paperwork Reduction Act

The Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)) requires that the FAA consider the impact of paperwork and other information collection burdens imposed on the public. The FAA has determined that there is no new requirement for information collection associated with this direct final rule.

F. International Compatibility

In keeping with U.S. obligations under the Convention on International Civil Aviation, it is FAA policy to conform to ICAO Standards and Recommended Practices to the maximum extent practicable. The FAA has reviewed the corresponding ICAO Standards and Recommended Practices and has identified the following difference. Once this rule is effective, the FAA's regulations will no longer include the definitions of Category IIIa, IIIb, and IIIc operations. This differs from ICAO Standards and Recommended Practices because ICAO's Annex 6 and Annex 10 include the Category IIIa, IIIb, and IIIc definitions. Until such time ICAO removes these definitions from its annexes, the FAA will be required to file a Difference with ICAO.

G. Environmental Analysis

FAA Order 1050.1E identifies FAA actions that are categorically excluded from preparation of an environmental assessment or environmental impact statement under the National Environmental Policy Act in the absence of extraordinary circumstances. The FAA has determined this rulemaking action qualifies for the categorical exclusion identified in paragraph 312f and involves no extraordinary circumstances.

IV. Executive Order Determinations

A. Executive Order 13132, Federalism

The FAA has analyzed this final rule under the principles and criteria of Executive Order 13132, Federalism. The agency determined that this action will not have a substantial direct effect on the States, or the relationship between the Federal Government and the States, or on the distribution of power and responsibilities among the various levels of government, and, therefore, does not have Federalism implications.

B. Executive Order 13211, Regulations That Significantly Affect Energy Supply, Distribution, or Use

The FAA analyzed this final rule under Executive Order 13211, Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use (May 18, 2001). The agency has determined that it is not a ''significant energy action'' under the executive order and it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

V. Additional Information

A. Comments Invited

The FAA invites interested persons to participate in this rulemaking by submitting written comments, data, or views. The agency also invites comments relating to the economic, environmental, energy, or federalism impacts that might result from adopting the rulemaking action in this document. The most helpful comments reference a specific portion of the rulemaking action, explain the reason for any recommended change, and include supporting data. To ensure the docket does not contain duplicate comments, commenters should send only one copy of written comments, or if comments are filed electronically, commenters should submit only one time.

The FAA will file in the docket all comments it receives, as well as a report summarizing each substantive public contact with FAA personnel concerning this rulemaking. Before acting on this rulemaking action, the FAA will consider all comments it receives on or before the closing date for comments. The FAA will consider comments filed after the comment period has closed if it is possible to do so without incurring expense or delay. The agency may change this rulemaking action in light of the comments it receives.

B. Availability of Rulemaking Documents

An electronic copy of rulemaking documents may be obtained from the Internet by—

1. Searching the Federal eRulemaking Portal (*http://www.regulations.gov*);
2. Visiting the FAA's Regulations and Policies Web page at *http://www.faa.gov/regulations_policies*; or
3. Accessing the Government Printing Office's Web page at *http://www.fdsys.gov.*

Copies may also be obtained by sending a request to the Federal Aviation Administration, Office of Rulemaking, ARM–1, 800 Independence Avenue SW., Washington, DC 20591, or by calling (202) 267–9680. Commenters must identify the docket or amendment number of this rulemaking.

All documents the FAA considered in developing this rulemaking action, including economic analyses and technical reports, may be accessed from the Internet through the Federal eRulemaking Portal referenced in item (1) above.

List of Subjects in 14 CFR Part 1

Air transportation.

The Amendment

In consideration of the foregoing, the Federal Aviation Administration amends chapter I of title 14, Code of Federal Regulations as follows:

PART 1—DEFINITIONS AND ABBREVIATIONS

■ 1. The authority citation for part 1 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

■ 2. Amend § 1.1 by removing the definitions of ''Category IIIa operations,'' ''Category IIIb operations,'' and ''Category IIIc operations.''

Issued in Washington, DC, on February 7, 2012.

Michael P. Huerta,

Acting Administrator.

[FR Doc. 2012–3692 Filed 2–15–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2012–0107; Directorate Identifier 2012–NM–018–AD; Amendment 39–16955; AD 2012–03–51]

RIN 2120–AA64

Airworthiness Directives; Airplanes Originally Manufactured by Lockheed for the Military as P2V Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule; request for comments.

SUMMARY: We are adopting a new airworthiness directive (AD) for certain airplanes originally manufactured by Lockheed for the military as P2V airplanes. This emergency AD was sent previously to all known U.S. owners and operators of these airplanes. This AD requires cleaning of the forward lower spar cap between wing stations 40 and 84.5 (right and left), and doing a detailed inspection for cracks, working fasteners, and other anomalies, including surface damage in the form of a nick, gouge, or corrosion; and repairing if necessary. This AD was prompted by a report of a significant crack in the principle wing structure. We are issuing this AD to detect and

correct cracks, working fasteners, and other anomalies in the principle wing structure, which could cause significant loss of structural integrity of the wing.

DATES: This AD is effective March 2, 2012 to all persons except those persons to whom it was made immediately effective by Emergency AD 2012–03–51, issued on February 6, 2012, which contained the requirements of this amendment.

We must receive comments on this AD by April 2, 2012.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov*. Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov;* or in person at the Docket Operations Office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Operations Office (phone: 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT:
Roger Caldwell, Aerospace Engineer, Denver Aircraft Certification Office, FAA, 26805 East 68th Avenue, Denver, CO 80249; phone: 303–342–1086; fax: 303–342–1088; e-mail: *roger.caldwell@faa.gov*.

SUPPLEMENTARY INFORMATION:

Discussion

On February 6, 2012, we issued Emergency AD 2012–03–51, which requires cleaning of the forward lower spar cap between wing stations 40 and 84.5 (right and left), and doing a detailed inspection for cracks, working fasteners, and other anomalies, including surface damage in the form of a nick, gouge, or corrosion; and repairing if necessary. That AD also requires sending inspection results (both positive and negative) to the FAA. This AD was prompted by a report of a significant crack in the principle wing structure on a Neptune Aviation Service, Inc. Model SP–2H (P2V–7) airplane. A crack approximately 24 inches long was found in the left side wing front spar and lower skin just outboard of the fuselage side of wing station 40. The crack propagated through the wing front spar web, lower chord, and wing lower skin through stringer No. 22 and aft to stringer No. 21. The cause of the cracking is unknown at this time. This condition, if not detected and corrected, could result in significant loss of structural integrity of the wing.

FAA's Determination

We are issuing this AD because we evaluated all the relevant information and determined the unsafe condition described previously is likely to exist or develop in other products of the same type design.

AD Requirements

This AD requires cleaning of the forward lower spar cap between wing stations 40 and 84.5 (right and left), and doing a detailed inspection for cracks, working fasteners, and other anomalies, including surface damage in the form of a nick, gouge, or corrosion; and repairing if necessary. This AD also requires sending inspection results (both positive and negative) to the FAA.

Interim Action

We consider this AD interim action. If final action is later identified, we might consider further rulemaking then.

FAA's Determination of the Effective Date

An unsafe condition exists that requires the immediate adoption of this AD. The FAA has found that the risk to the flying public justifies waiving notice and comment prior to adoption of this rule because of a report of a significant crack in the principle wing structure on a Neptune Aviation Service, Inc. Model SP–2H (P2V–7) airplane. This condition, if not detected and corrected, could result in significant loss of structural integrity of the wing. Therefore, we find that notice and opportunity for prior public comment are impracticable and that good cause exists for making this amendment effective in less than 30 days.

Comments Invited

This AD is a final rule that involves requirements affecting flight safety and was not preceded by notice and an opportunity for public comment. However, we invite you to send any written data, views, or arguments about this AD. Send your comments to an address listed under the **ADDRESSES** section. Include the docket number FAA–2012–0107 and Directorate Identifier 2012–NM–018–AD at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this AD. We will consider all comments received by the closing date and may amend this AD because of those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov*, including any personal information you provide. We will also post a report summarizing each substantive verbal contact we receive about this AD.

Costs of Compliance

We estimate that this AD affects 38 airplanes of U.S. registry.

We estimate the following costs to comply with this AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Inspection	Up to 80 work-hours × $85 per hour = $6,800	$100	Up to $6,900	Up to $262,200.

No definitive data are available for repair costs at this time.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs describes in more detail the scope of the Agency's authority.

We are issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: ''General requirements.'' Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

This AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect 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.

For the reasons discussed above, I certify that this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866,

(2) Is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979),

(3) Will not affect intrastate aviation in Alaska, and

(4) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by adding the following new airworthiness directive (AD):

2012–03–51 Lockheed (Original Manufacturer): Amendment 39–16955; Docket No. FAA–2012–0107; Directorate Identifier 2012–NM–018–AD.

(a) Effective Date

This AD is effective March 2, 2012 to all persons except those persons to whom it was made immediately effective by Emergency AD 2012–03–51, issued on February 6, 2012, which contained the requirements of this amendment.

(b) Affected ADs

None.

(c) Applicability

This AD applies to all of the airplanes identified in paragraphs (c)(1), (c)(2), (c)(3), (c)(4), (c)(5), (c)(6), and (c)(7) of this AD, certificated in any category:

(1) Aero Union Corporation Model SP–2H (P2V–7) airplanes;

(2) Central Air Service, Inc. Model SP–2H (P2V–7) airplanes;

(3) Evergreen Air Center Model SP–2H (P2V–7) airplanes;

(4) Hawkins and Powers Aviation, Inc. Model HP–P2V–7 airplanes;

(5) Minden Air Corp Model SP–2H (P2V–7) airplanes;

(6) Neptune Aviation Service, Inc. Model SP–2H (P2V–7) airplanes; and

(7) USDA Forest Service (type certificate previously held by U.S. Department of Agriculture) Model P2V–5F (SP–2E) airplanes.

(d) Subject

Joint Aircraft System Component (JASC)/ Air Transport Association (ATA) of America Code 57, Wings.

(e) Unsafe Condition

This AD was prompted by a report of a significant crack in the principle wing structure on a Neptune Aviation Service, Inc. Model SP–2H (P2V–7) airplane. We are issuing this AD to detect and correct cracks, working fasteners, and other anomalies in the principle wing structure, which could cause significant loss of structural integrity of the wing.

(f) Compliance

Comply with this AD within the compliance times specified.

(g) Inspections

Within one day after the effective date of this AD: Do the actions specified in paragraphs (g)(1), (g)(2), and (g)(3) of this AD.

(1) Gain access to the wing spar box between wing stations 40 and 84.5 (right and left sides of the airplane) through an access panel that allows for inspecting the forward lower spar cap assembly and remove or reposition any internal fuel bladder assembly that impedes access.

(2) Clean the exposed surface of the forward lower spar cap between wing stations 40 and 84.5 (right and left), and do a detailed inspection for cracks, working fasteners, and other anomalies, including surface damage in the form of a nick, gouge, or corrosion, of the forward lower spar cap between wing stations 40 and 84.5 (right and left).

(3) If any crack, working fastener, or other anomaly is found during any inspection required by paragraph (g)(2) of this AD, before further flight, repair in accordance with a method approved by the Manager, Denver Aircraft Certification Office (ACO), FAA. For a repair method to be approved by the Manager, Denver ACO, as required by this paragraph, the Manager's approval letter must specifically refer to this AD.

(h) Definition

For the purposes of this AD, a detailed inspection is: ''An intensive examination of a specific item, installation, or assembly to detect damage, failure, or irregularity. Available lighting is normally supplemented with a direct source of good lighting at an intensity deemed appropriate. Inspection aids such as mirror, magnifying lenses, etc., may be necessary. Surface cleaning and elaborate procedures may be required.

(i) Reporting

Within 10 days after doing the inspection required by paragraph (g) of this AD: Submit a report of the findings (both positive and negative) of the inspections required by paragraph (g) of this AD to the Denver ACO, FAA, Attention: Roger Caldwell, 26805 East 68th Avenue, Denver, CO 80249; phone: 303–342–1086; fax: 303–342–1088; e-mail: *roger.caldwell@faa.gov*. The report must include a detailed figure or picture of all cracks and damage and the location, orientation, and size of all cracks and damage. The report must also include the airplane serial number, the number of landings and flight hours on the airplane, and a description of how the airplane is operated (e.g., firefighting, photography, etc.).

(j) Paperwork Reduction Act Burden Statement

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2120–0056. Public reporting for this collection of information is estimated to be approximately 5 minutes per response, including the time for reviewing instructions, completing and reviewing the collection of information. All responses to this collection of information are mandatory. Comments concerning the accuracy of this burden and suggestions for reducing the burden should be directed to the FAA at: 800 Independence Ave. SW., Washington, DC 20591, Attn: Information Collection Clearance Officer, AES–200.

(k) Special Flight Permit

Special flight permits, as described in Section 21.197 and Section 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199), are not allowed unless approved in accordance with the procedures specified in paragraph (l) of this AD.

(l) Alternative Methods of Compliance (AMOCs)

(1) The Manager, Denver ACO, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19,

send your request to your principal inspector or local Flight Standards District Office, as appropriate. If sending information directly to the manager of the ACO, send it to the attention of the person identified in the Related Information section of this AD.

(2) Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the local flight standards district office/certificate holding district office.

(m) Related Information

For further information about this AD, contact: Roger Caldwell, Aerospace Engineer, Denver Aircraft Certification Office, FAA, 26805 East 68th Avenue, Denver, CO 80249; phone: 303–342–1086; fax: 303–342–1088; e-mail: *roger.caldwell@faa.gov.*

(n) Material Incorporated by Reference

None.

Issued in Renton, Washington, on February 9, 2012.

Ali Bahrami,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2012–3618 Filed 2–15–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 97

[Docket No. 30826; Amdt. No. 3464]

Standard Instrument Approach Procedures, and Takeoff Minimums and Obstacle Departure Procedures; Miscellaneous Amendments

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This rule establishes, amends, suspends, or revokes Standard Instrument Approach Procedures (SIAPs) and associated Takeoff Minimums and Obstacle Departure Procedures for operations at certain airports. These regulatory actions are needed because of the adoption of new or revised criteria, or because of changes occurring in the National Airspace System, such as the commissioning of new navigational facilities, adding new obstacles, or changing air traffic requirements. These changes are designed to provide safe and efficient use of the navigable airspace and to promote safe flight operations under instrument flight rules at the affected airports.

DATES: This rule is effective February 16, 2012. The compliance date for each SIAP, associated Takeoff Minimums, and ODP is specified in the amendatory provisions.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of February 16, 2012.

ADDRESSES: Availability of matters incorporated by reference in the amendment is as follows:

For Examination—

1. FAA Rules Docket, FAA Headquarters Building, 800 Independence Avenue SW., Washington, DC 20591;

2. The FAA Regional Office of the region in which the affected airport is located;

3. The National Flight Procedures Office, 6500 South MacArthur Blvd., Oklahoma City, OK 73169 or

4. The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Availability—All SIAPs and Takeoff Minimums and ODPs are available online free of charge. Visit *http://www.nfdc.faa.gov* to register. Additionally, individual SIAP and Takeoff Minimums and ODP copies may be obtained from:

1. FAA Public Inquiry Center (APA–200), FAA Headquarters Building, 800 Independence Avenue SW., Washington, DC 20591; or

2. The FAA Regional Office of the region in which the affected airport is located.

FOR FURTHER INFORMATION CONTACT: Richard A. Dunham III, Flight Procedure Standards Branch (AFS–420), Flight Technologies and Programs Divisions, Flight Standards Service, Federal Aviation Administration, Mike Monroney Aeronautical Center, 6500 South MacArthur Blvd., Oklahoma City, OK 73169 (Mail Address: P.O. Box 25082, Oklahoma City, OK 73125), Telephone: (405) 954–4164.

SUPPLEMENTARY INFORMATION: This rule amends Title 14 of the Code of Federal Regulations, Part 97 (14 CFR part 97), by establishing, amending, suspending, or revoking SIAPS, Takeoff Minimums and/or ODPS. The complete regulators description of each SIAP and its associated Takeoff Minimums or ODP for an identified airport is listed on FAA form documents which are incorporated by reference in this amendment under 5 U.S.C. 552(a), 1 CFR part 51, and 14 CFR part 97.20. The applicable FAA Forms are FAA Forms 8260–3, 8260–4, 8260–5, 8260–15A, and 8260–15B when required by an entry on 8260–15A.

The large number of SIAPs, Takeoff Minimums and ODPs, in addition to their complex nature and the need for a special format make publication in the **Federal Register** expensive and impractical. Furthermore, airmen do not use the regulatory text of the SIAPs, Takeoff Minimums or ODPs, but instead refer to their depiction on charts printed by publishers of aeronautical materials. The advantages of incorporation by reference are realized and publication of the complete description of each SIAP, Takeoff Minimums and ODP listed on FAA forms is unnecessary. This amendment provides the affected CFR sections and specifies the types of SIAPs and the effective dates of the associated Takeoff Minimums and ODPs. This amendment also identifies the airport and its location, the procedure, and the amendment number.

The Rule

This amendment to 14 CFR part 97 is effective upon publication of each separate SIAP, Takeoff Minimums and ODP as contained in the transmittal. Some SIAP and Takeoff Minimums and textual ODP amendments may have been issued previously by the FAA in a Flight Data Center (FDC) Notice to Airmen (NOTAM) as an emergency action of immediate flight safety relating directly to published aeronautical charts. The circumstances which created the need for some SIAP and Takeoff Minimums and ODP amendments may require making them effective in less than 30 days. For the remaining SIAPS and Takeoff Minimums and ODPS, an effective date at least 30 days after publication is provided.

Further, the SIAPs and Takeoff Minimums and ODPS contained in this amendment are based on the criteria contained in the U.S. Standard for Terminal Instrument Procedures (TERPS). In developing these SIAPS and Takeoff Minimums and ODPs, the TERPS criteria were applied to the conditions existing or anticipated at the affected airports. Because of the close and immediate relationship between these SIAPs, Takeoff Minimums and ODPs, and safety in air commerce, I find that notice and public procedures before adopting these SIAPS, Takeoff Minimums and ODPs are impracticable and contrary to the public interest and, where applicable, that good cause exists for making some SIAPs effective in less than 30 days.

Conclusion

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule '' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26,1979); and (3)does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. For the same reason, the FAA certifies that this amendment will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR part 97

Air Traffic Control, Airports, Incorporation by reference, and Navigation (air).

Issued in Washington, DC, on February 3, 2012.

John McGraw,

Deputy Director, Flight Standards Service.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me, Title 14, Code of Federal Regulations, Part 97 (14 CFR part 97) is amended by establishing, amending, suspending, or revoking Standard Instrument Approach Procedures and/or Takeoff Minimums and/or Obstacle Departure Procedures effective at 0902 UTC on the dates specified, as follows:

PART 97—STANDARD INSTRUMENT APPROACH PROCEDURES

■ 1. The authority citation for part 97 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40106, 40113, 40114, 40120, 44502, 44514, 44701, 44719, 44721–44722.

■ 2. Part 97 is amended to read as follows:

Effective 8 MAR 2012

Centre, AL, Centre-Piedmont-Cherokee County Rgnl, RNAV (GPS) RWY 7, Amdt 1
Centre, AL, Centre-Piedmont-Cherokee County Rgnl, RNAV (GPS) RWY 25, Amdt 1
Hot Springs, AR, Memorial Field, Takeoff Minimums and Obstacle DP, Amdt 6
Cumberland, MD, Greater Cumberland Rgnl, LOC/DME RWY 23, Amdt 6A
Escanaba, MI, Delta County, ILS OR LOC RWY 9, Amdt 2A
Hastings, NE., Hastings Muni, VOR RWY 4, Amdt 6
Albuquerque, NM, Albuquerque Intl Sunport, ILS OR LOC RWY 3, Amdt 2B
Albuquerque, NM, Albuquerque Intl Sunport, ILS OR LOC RWY 8, Amdt 5G
Big Spring, TX, Big Spring McMahon-Wrinkle, Takeoff Minimums and Obstacle DP, Amdt 3
Dallas, TX, Collin County Rgnl at McKinney, ILS OR LOC RWY 17, Amdt 3A
Dallas, TX, Dallas Love Field, ILS OR LOC RWY 31R, ILS RWY 31R (SA CAT I), ILS RWY 31R (SA CAT II), Amdt 5
Weslaco, TX, Mid Valley, Takeoff Minimums and Obstacle DP, Orig

Effective 5 APR 2012

Coldfoot, AK, Coldfoot, RNAV (GPS) RWY 1, Amdt 1
Mobile, AL, Mobile Downtown, ILS OR LOC RWY 32, Amdt 2A
Fort Lauderdale, FL, Fort Lauderdale/Hollywood Intl, LOC RWY 9R, Amdt 5, CANCELLED
Fort Lauderdale, FL, Fort Lauderdale/Hollywood Intl, RNAV (GPS) RWY 27L, Orig-A, CANCELLED
Fort Lauderdale, FL, Fort Lauderdale/Hollywood Intl, RNAV (GPS) Y RWY 9R, Amdt 3, CANCELLED
Fort Lauderdale, FL, Fort Lauderdale/Hollywood Intl, RNAV (RNP) Z RWY 9R, Orig-D, CANCELLED
Belle Plaine, IA, Belle Plaine Muni, Takeoff Minimums and Obstacle DP, Amdt 1
Cedar Rapids, IA, The Eastern Iowa, ILS OR LOC RWY 27, Amdt 6C
Grinnell, IA, Grinnell Rgnl, NDB RWY 13, Amdt 4, CANCELLED
Oelwein, IA, Oelwein Muni, NDB RWY 13, Amdt 2A, CANCELLED
Idaho Falls, ID, Idaho Falls Rgnl, RNAV (GPS) Y RWY 20, Amdt 1B
Cambridge, MN, Cambridge Muni, Takeoff Minimums and Obstacle DP, Orig
Pipestone, MN, Pipestone Muni, NDB RWY 36, Amdt 7, CANCELLED
Rushford, MN, Rushford Muni, Takeoff Minimums and Obstacle DP, Amdt 2
Ebensburg, PA, Ebensburg, RNAV (GPS) RWY 25, Orig-A
Philipsburg, PA, Mid-State, RNAV (GPS) RWY 16, Orig-A
Yankton, SD, Chan Gurney Muni, ILS OR LOC RWY 31, Amdt 4
Plainview, TX, Hale County, Takeoff Minimums and Obstacle DP, Orig
Yakima, WA, Yakima Air Terminal/McAllister Field, ILS Y RWY 27, Orig-B
Yakima, WA, Yakima Air Terminal/McAllister Field, ILS Z RWY 27, Amdt 27B
Phillips, WI, Price County, RNAV (GPS) RWY 1, Orig-A
Reedsburg, WI, Reedsburg Muni, RNAV (GPS) RWY 18, Orig
Reedsburg, WI, Reedsburg Muni, RNAV (GPS) RWY 36, Orig
Reedsburg, WI, Reedsburg Muni, Takeoff Minimums and Obstacle DP, Amdt 2
Reedsburg, WI, Reedsburg Muni, VOR–A, Amdt 5
Casper, WY, Casper/Natrona County Intl, ILS OR LOC RWY 3, Amdt 7
Casper, WY, Casper/Natrona County Intl, VOR/DME RWY 3, Amdt 6
Casper, WY, Casper/Natrona County Intl, VOR/DME RWY 21 Amdt 9
Laramie, WY, Laramie Rgnl, LARAMIE ONE Graphic DP
Laramie, WY, Laramie Rgnl, Takeoff Minimums and Obstacle DP, Amdt 2

[FR Doc. 2012–3431 Filed 2–15–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 97

[Docket No. 30827; Amdt. No. 3465]

Standard Instrument Approach Procedures, and Takeoff Minimums and Obstacle Departure Procedures; Miscellaneous Amendments

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This rule establishes, amends, suspends, or revokes Standard Instrument Approach Procedures (SIAPs) and associated Takeoff Minimums and Obstacle Departure Procedures for operations at certain airports. These regulatory actions are needed because of the adoption of new or revised criteria, or because of changes occurring in the National Airspace System, such as the commissioning of new navigational facilities, adding new obstacles, or changing air traffic requirements. These changes are designed to provide safe and efficient use of the navigable airspace and to promote safe flight operations under instrument flight rules at the affected airports.

DATES: This rule is effective February 16, 2012. The compliance date for each SIAP, associated Takeoff Minimums, and ODP is specified in the amendatory provisions.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of February 16, 2012.

ADDRESSES: Availability of matter incorporated by reference in the amendment is as follows:

For Examination—

1. FAA Rules Docket, FAA Headquarters Building, 800 Independence Avenue SW., Washington, DC 20591;
2. The FAA Regional Office of the region in which the affected airport is located;
3. The National Flight Procedures Office, 6500 South MacArthur Blvd., Oklahoma City, OK 73169 or
4. The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Availability—All SIAPs are available online free of charge. Visit *nfdc.faa.gov* to register. Additionally, individual SIAP and Takeoff Minimums and ODP copies may be obtained from:

1. FAA Public Inquiry Center (APA–200), FAA Headquarters Building, 800 Independence Avenue SW., Washington, DC 20591; or

2. The FAA Regional Office of the region in which the affected airport is located.

FOR FURTHER INFORMATION CONTACT: Richard A. Dunham III, Flight Procedure Standards Branch (AFS–420) Flight Technologies and Programs Division, Flight Standards Service, Federal Aviation Administration, Mike Monroney Aeronautical Center, 6500 South MacArthur Blvd., Oklahoma City, OK 73169 (Mail Address: P.O. Box 25082 Oklahoma City, OK 73125), telephone: (405) 954–4164.

SUPPLEMENTARY INFORMATION: This rule amends Title 14, Code of Federal Regulations, Part 97 (14 CFR part 97) by amending the referenced SIAPs. The complete regulatory description of each SIAP is listed on the appropriate FAA Form 8260, as modified by the National Flight Data Center (FDC)/Permanent Notice to Airmen (P–NOTAM), and is incorporated by reference in the amendment under 5 U.S.C. 552(a), 1 CFR part 51, and § 97.20 of Title 14 of the Code of Federal Regulations.

The large number of SIAPs, their complex nature, and the need for a special format make their verbatim publication in the **Federal Register** expensive and impractical. Further, airmen do not use the regulatory text of the SIAPs, but refer to their graphic depiction on charts printed by publishers of aeronautical materials. Thus, the advantages of incorporation by reference are realized and publication of the complete description of each SIAP contained in FAA form documents is unnecessary. This amendment provides the affected CFR sections and specifies the types of SIAP and the corresponding effective dates. This amendment also identifies the airport and its location, the procedure and the amendment number.

The Rule

This amendment to 14 CFR part 97 is effective upon publication of each separate SIAP as amended in the transmittal. For safety and timeliness of change considerations, this amendment incorporates only specific changes contained for each SIAP as modified by FDC/P–NOTAMs.

The SIAPs, as modified by FDC P–NOTAM, and contained in this amendment are based on the criteria contained in the U.S. Standard for Terminal Instrument Procedures (TERPS). In developing these changes to SIAPs, the TERPS criteria were applied only to specific conditions existing at the affected airports. All SIAP amendments in this rule have been previously issued by the FAA in a FDC NOTAM as an emergency action of immediate flight safety relating directly to published aeronautical charts. The circumstances which created the need for all these SIAP amendments requires making them effective in less than 30 days.

Because of the close and immediate relationship between these SIAPs and safety in air commerce, I find that notice and public procedure before adopting these SIAPs are impracticable and contrary to the public interest and, where applicable, that good cause exists for making these SIAPs effective in less than 30 days.

Conclusion

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. For the same reason, the FAA certifies that this amendment will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 97

Air Traffic Control, Airports, Incorporation by reference, and Navigation (air).

Issued in Washington, DC, on February 3, 2012.

John McGraw,

Deputy Director, Flight Standards Service.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me, Title 14, Code of Federal regulations, Part 97, 14 CFR part 97, is amended by amending Standard Instrument Approach Procedures, effective at 0901 UTC on the dates specified, as follows:

PART 97—STANDARD INSTRUMENT APPROACH PROCEDURES

■ 1. The authority citation for part 97 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40106, 40113, 40114, 40120, 44502, 44514, 44701, 44719, 44721–44722.

■ 2. Part 97 is amended to read as follows:

§§ 97.23, 97.25, 97.27, 97.29, 97.31, 97.33 and 97.35 [Amended]

By amending: § 97.23 VOR, VOR/DME, VOR or TACAN, and VOR/DME or TACAN; § 97.25 LOC, LOC/DME, LDA, LDA/DME, SDF, SDF/DME; § 97.27 NDB, NDB/DME; § 97.29 ILS, ILS/DME, MLS, MLS/DME, MLS/RNAV; § 97.31 RADAR SIAPs; § 97.33 RNAV SIAPs; and § 97.35 COPTER SIAPs, Identified as follows:

EFFECTIVE UPON PUBLICATION

AIRAC Date	State	City	Airport	FDC No.	FDC Date	Subject
8–Mar–12	TX	Yoakum	Yoakum Muni	1/5116	1/12/12	NDB RWY 31, Amdt 3
8–Mar–12	TX	Yoakum	Yoakum Muni	1/5117	1/12/12	RNAV (GPS) RWY 31, Orig-A
8–Mar–12	NJ	Berlin	Camden County	2/2036	1/24/12	RNAV (GPS) RWY 5, Orig-A
8–Mar–12	NE	Hastings	Hastings Muni	2/2069	1/24/12	RNAV (GPS) RWY 14, Orig
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2713	1/27/12	ILS or LOC RWY 9L, ILS RWY 9L (CAT II), ILS RWY 9L (CAT III), Orig-C
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2714	1/27/12	ILS or LOC RWY 10, ILS RWY 10 (CAT II), ILS RWY 10 (CAT III), Amdt 16A
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2715	1/27/12	ILS or LOC RWY 14L, ILS RWY 14L (CAT II), ILS RWY 14L (CAT III), Amdt 29C

AIRAC Date	State	City	Airport	FDC No.	FDC Date	Subject
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2716	1/27/12	ILS or LOC RWY 14R, ILS RWY 14R (CAT II), ILS RWY 14R (CAT III), Amdt 30B
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2717	1/27/12	ILS or LOC RWY 27R, ILS RWY 27R (CAT II), ILS RWY 27R (CAT III), Orig-A
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2718	1/27/12	ILS or LOC RWY 27L, ILS RWY 27L (CAT II), ILS RWY 27L (CAT III), Amdt 28A
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2719	1/27/12	ILS or LOC RWY 28, ILS RWY 28 (CAT II), ILS RWY 28 (CAT III), Amdt 15A
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2728	1/24/12	ILS or LOC RWY 5R, ILS RWY 5R (CAT II), ILS RWY 5R (CATIII), Amdt 5A
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2729	1/24/12	ILS or LOC RWY 5L, ILS RWY 5L (CAT II), ILS RWY 5L (CAT III), Amdt 3B
8–Mar–12	TX	Austin	Austin-Bergstrom Intl	2/2730	1/24/12	ILS or LOC RWY 17L, ILS RWY 17L (CAT II), ILS RWY 17L (CAT III), Amdt 1A
8–Mar–12	OK	Tulsa	Tulsa Intl	2/2731	1/25/12	RNAV (GPS) RWY 18L, Amdt 1
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2749	1/27/12	RNAV (GPS) RWY 10, Amdt 3A
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2755	1/24/12	RNAV (GPS) Y RWY 23L, Amdt 2
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2756	1/27/12	RNAV (GPS) RWY 14R, Amdt 2
8–Mar–12	TX	Austin	Austin-Bergstrom Intl	2/2757	1/24/12	ILS or LOC RWY 17R, Amdt 3A
8–Mar–12	TX	Austin	Austin-Bergstrom Intl	2/2762	1/24/12	ILS or LOC RWY 35L, Amdt 4A
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2763	1/27/12	RNAV (GPS) RWY 9R, Amdt 2
8–Mar–12	OK	Tulsa	Tulsa Intl	2/2764	1/25/12	RNAV (RNP) Z RWY 18R, Orig-A
8–Mar–12	TX	Dallas-Fort Worth ..	Dallas-Fort Worth Intl	2/2765	1/24/12	ILS or LOC RWY 18R, ILS RWY 18R (CAT II), ILS RWY 18R (CAT III), Amdt 7 A
8–Mar–12	OK	Tulsa	Tulsa Intl	2/2766	1/25/12	ILS or LOC RWY 18R, Amdt 7A
8–Mar–12	TX	Dallas-Fort Worth ..	Dallas-Fort Worth Intl	2/2767	1/24/12	ILS or LOC RWY 17C, ILS RWY 17C (CAT II), ILS RWY 17C (CAT III), Amdt 9A
8–Mar–12	TX	Dallas-Fort Worth ..	Dallas-Fort Worth Intl	2/2769	1/24/12	ILS or LOC RWY 17L, ILS RWY 17L (CAT II), ILS RWY 17L (CAT III), Amdt 5C
8–Mar–12	TX	Dallas-Fort Worth ..	Dallas-Fort Worth Intl	2/2773	1/24/12	ILS or LOC RWY 35C, ILS RWY 35C (CAT II), ILS RWY 35C (CAT III), Amdt 1A
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2774	1/24/12	RNAV (RNP) Z RWY 5R, Orig-A
8–Mar–12	TX	Dallas-Fort Worth ..	Dallas-Fort Worth Intl	2/2775	1/24/12	ILS or LOC RWY 35R, ILS RWY 35R (CAT II), ILS RWY 35R (CAT III), Amdt 3A
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2776	1/24/12	RNAV (RNP) Z RWY 23R, Orig-B
8–Mar–12	TX	Austin	Austin-Bergstrom Intl	2/2777	1/24/12	ILS or LOC RWY 35R, Amdt 1A
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2778	1/27/12	RNAV (GPS) RWY 28, Amdt 2B
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2779	1/24/12	RNAV (RNP) Z RWY 5L, Orig-B
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2782	1/24/12	ILS or LOC RWY 23R, Amdt 3B
8–Mar–12	OH	Columbus	Port Columbus Intl	2/2785	1/24/12	ILS or LOC RWY 10R, Amdt 8B
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2787	1/24/12	RNAV (GPS) Y RWY 5L, Amdt 2
8–Mar–12	TX	Austin	Austin-Bergstrom Intl	2/2788	1/24/12	RNAV (GPS) RWY 17R, Orig
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2789	1/27/12	ILS or LOC RWY 9R, Amdt 9A
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2794	1/27/12	RNAV (GPS) RWY 27L, Amdt 2
8–Mar–12	OH	Columbus	Port Columbus Intl	2/2796	1/24/12	RNAV (GPS) Y RWY 10R, Amdt 2
8–Mar–12	OH	Columbus	Port Columbus Intl	2/2798	1/24/12	RNAV (RNP) Z RWY 10R, Orig-A
8–Mar–12	OH	Columbus	Port Columbus Intl	2/2801	1/24/12	ILS or LOC RWY 28R, Amdt 3A
8–Mar–12	OH	Columbus	Port Columbus Intl	2/2803	1/24/12	RNAV (GPS) Y RWY 28R, Amdt 1
8–Mar–12	OH	Columbus	Port Columbus Intl	2/2804	1/24/12	ILS or LOC RWY 10L, Amdt 18A
8–Mar–12	MN	Minneapolis	Minneapolis-St Paul Intl/ Wold-Chamberlain.	2/2809	1/26/12	RNAV (GPS) RWY 30R, Amdt 1A
8–Mar–12	OH	Columbus	Port Columbus Intl	2/2812	1/24/12	RNAV (RNP) Z RWY 28R, Orig-A
8–Mar–12	OK	Tulsa	Tulsa Intl	2/2813	1/25/12	RNAV (GPS) Y RWY 18R, Amdt 1A
8–Mar–12	OK	Tulsa	Tulsa Intl	2/2814	1/25/12	ILS or LOC RWY 18L, Amdt 15A

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8–Mar–12	OH	Columbus	Port Columbus Intl	2/2815	1/24/12	ILS or LOC RWY 28L, Amdt 28A
8–Mar–12	MN	Minneapolis	Minneapolis-St Paul Intl/ Wold-Chamberlain.	2/2816	1/26/12	CONVERGING ILS RWY 30R, Amdt 1
8–Mar–12	OK	Tulsa	Tulsa Intl	2/2817	1/25/12	RNAV (GPS) RWY 36L, Orig-A
8–Mar–12	MN	Minneapolis	Minneapolis-St Paul Intl/ Wold-Chamberlain.	2/2819	1/26/12	RNAV (GPS) RWY 30L, Amdt 2
8–Mar–12	TX	Austin	Austin-Bergstrom Intl	2/2820	1/24/12	RNAV (GPS) RWY 35R, Orig
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2821	1/27/12	ILS or LOC RWY 32R, Amdt 21D
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2824	1/27/12	RNAV (GPS) RWY 27R, Orig
8–Mar–12	TX	Austin	Austin-Bergstrom Intl	2/2829	1/24/12	RNAV (GPS) Z RWY 35L, Orig
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2838	1/27/12	RNAV (GPS) RWY 14L, Amdt 1C
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2841	1/24/12	RNAV (GPS) Y RWY 5R, Amdt 2
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2842	1/24/12	RNAV (GPS) Y RWY 23R, Amdt 2
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2843	1/24/12	RNAV (RNP) Z RWY 23L, Orig-A
8–Mar–12	IN	Indianapolis	Indianapolis Intl	2/2845	1/24/12	ILS or LOC RWY 23L, Amdt 5A
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2848	1/27/12	RNAV (GPS) RWY 4R, Orig-C
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2849	1/24/12	RNAV (GPS) RWY 17R, Amdt 1
8–Mar–12	IL	Chicago	Chicago O'Hare Intl	2/2851	1/27/12	RNAV (GPS) RWY 4L, Amdt 1B
8–Mar–12	MN	Minneapolis	Minneapolis-St Paul Intl/ Wold-Chamberlain.	2/2852	1/26/12	RNAV (GPS) RWY 12L, Amdt 2
8–Mar–12	MN	Minneapolis	Minneapolis-St Paul Intl/ Wold-Chamberlain.	2/2853	1/26/12	RNAV (GPS) RWY 12R, Amdt 1
8–Mar–12	TX	Austin	Austin-Bergstrom Intl	2/2855	1/24/12	RNAV (GPS) RWY 17L, Orig
8–Mar–12	MN	Minneapolis	Minneapolis-St Paul Intl/ Wold-Chamberlain.	2/2856	1/26/12	ILS or LOC RWY 30R, Amdt 13
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2872	1/24/12	ILS or LOC RWY 31R, Amdt 13A
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2873	1/24/12	ILS or LOC RWY 18L, Amdt 1A
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2876	1/24/12	RNAV (GPS) RWY 18L, Orig
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2877	1/24/12	RNAV (GPS) RWY 35R, Amdt 2A
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2879	1/24/12	RNAV (GPS) RWY 35C, Amdt 2
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2880	1/24/12	ILS or LOC RWY 17R, Amdt 22A
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2881	1/24/12	RNAV (GPS) RWY 18R, Orig
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2882	1/24/12	RNAV (GPS) RWY 36L, Amdt 2
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2883	1/24/12	RNAV (GPS) Y RWY 13R, Amdt 1A
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2884	1/24/12	RNAV (GPS) RWY 17L, Amdt 3A
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2885	1/24/12	RNAV (GPS) RWY 17C, Amdt 1
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2886	1/24/12	ILS or LOC RWY 36R, Amdt 4A
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2887	1/24/12	RNAV (GPS) RWY 36R, Amdt 2
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2888	1/24/12	ILS or LOC RWY 35L, Amdt 4A
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2889	1/24/12	ILS or LOC RWY 36L, Amdt 1A
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/2890	1/24/12	RNAV (GPS) RWY 35L, Amdt 1
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2923	1/27/12	ILS or LOC RWY 18L, Amdt 7
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2924	1/27/12	RNAV (RNP) Z RWY 18L, Orig-A
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2925	1/27/12	ILS RWY 18R (CAT II), Orig
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2926	1/27/12	ILS RWY 18R (CAT III), Orig
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2927	1/27/12	RNAV (GPS) Y RWY 18R, Orig
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2928	1/27/12	RNAV (RNP) Z RWY 18R, Orig-A
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2929	1/27/12	ILS or LOC RWY 36L, Orig
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2930	1/27/12	RNAV (GPS) Y RWY 36L, Orig
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2931	1/27/12	RNAV (GPS) Y RWY 36R, Amdt 3
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2932	1/27/12	ILS or LOC RWY 36R, Amdt 11
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2935	1/27/12	ILS RWY 36L (CAT II), Orig
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2936	1/27/12	RNAV (RNP) Z RWY 36L, Orig-A
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2937	1/27/12	RNAV (RNP) Z RWY 36R, Orig-A
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2938	1/27/12	ILS RWY 36R (CAT II), Amdt 11
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2939	1/27/12	RNAV (GPS) Y RWY 18L, Amdt 3
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2940	1/27/12	ILS or LOC RWY 18R, Orig
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2944	1/27/12	ILS RWY 36L (CAT III), Orig
8–Mar–12	NC	Charlotte	Charlotte/Douglas Intl	2/2945	1/27/12	ILS RWY 36R (CAT III), Amdt 11
8–Mar–12	AL	Huntsville	Huntsville Intl-Carl T Jones Field.	2/2988	1/25/12	ILS or LOC RWY 36R, Amdt 2
8–Mar–12	AL	Huntsville	Huntsville Intl-Carl T Jones Field.	2/2989	1/25/12	RNAV (GPS) RWY 36R, Amdt 1
8–Mar–12	AL	Huntsville	Huntsville Intl-Carl T Jones Field.	2/2990	1/25/12	ILS or LOC RWY 18L, Amdt 4A

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8–Mar–12	AL	Huntsville	Huntsville Intl-Carl T Jones Field.	2/2991	1/25/12	RNAV (GPS) RWY 18L, Amdt 1
8–Mar–12	AL	Huntsville	Huntsville Intl-Carl T Jones Field.	2/2992	1/25/12	ILS or LOC RWY 18R, Amdt 24A
8–Mar–12	AL	Huntsville	Huntsville Intl-Carl T Jones Field.	2/2993	1/25/12	ILS RWY 18R (CAT II), Amdt 24A
8–Mar–12	AL	Huntsville	Huntsville Intl-Carl T Jones Field.	2/2994	1/25/12	ILS or LOC RWY 36L, Amdt 10
8–Mar–12	AL	Huntsville	Huntsville Intl-Carl T Jones Field.	2/2995	1/25/12	RNAV (GPS) RWY 36L, Amdt 1
8–Mar–12	DC	Washington	Washington Dulles Intl	2/2996	1/26/12	RNAV (GPS) RWY 1L, Orig-A
8–Mar–12	DC	Washington	Washington Dulles Intl	2/2997	1/26/12	ILS RWY 19C (CAT III), Amdt 25
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3000	1/26/12	RNAV (GPS) Y RWY 19C, Amdt 3A
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3001	1/26/12	RNAV (GPS) Y RWY 19L, Amdt 2
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3002	2/1/12	ILS or LOC/DME RWY 19R, Amdt 1
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3003	1/26/12	ILS RWY 19R (CAT II), Amdt 1
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3004	1/26/12	ILS RWY 1L (CAT II), Amdt 1
8–Mar–12	MN	Minneapolis	Minneapolis-St Paul Intl/ Wold-Chamberlain.	2/3005	1/26/12	ILS or LOC RWY 12R, ILS RWY 12R (CAT II), ILS RWY 12R (CAT III), Amdt 9
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3006	1/26/12	ILS RWY 1L (CAT III), Amdt 1
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3007	1/26/12	ILS or LOC/DME RWY 19C, Amdt 25
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3009	2/1/12	ILS or LOC/DME RWY 1L, Amdt 1
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3010	1/26/12	RNAV (GPS) Y RWY 1R, Amdt 1A
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3011	1/26/12	RNAV (RNP) Z RWY 1R, Orig-C
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3012	1/26/12	ILS RWY 19C (CAT II), Amdt 25
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3013	1/26/12	RNAV (RNP) Z RWY 19C, Orig-C
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3014	1/26/12	ILS RWY 19R (CAT III), Amdt 1
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3015	1/26/12	RNAV (GPS) RWY 19R, Orig
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3016	2/1/12	ILS or LOC RWY 19L, Amdt 15
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3017	1/26/12	RNAV (RNP) Z RWY 19L, Orig-B
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3018	1/26/12	ILS or LOC/DME RWY 1C, Amdt 2
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3019	1/26/12	ILS RWY 1C (CAT II), Amdt 2
8–Mar–12	DC	Washington	Washington Dulles Intl	2/3020	1/26/12	RNAV (GPS) Y RWY 1C, Amdt 1
8–Mar–12	MN	Minneapolis	Minneapolis-St Paul Intl/ Wold-Chamberlain.	2/3021	1/26/12	ILS or LOC RWY 12L, ILS RWY 12L (CAT II), ILS RWY 12L (CAT III), Amdt 8
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3023	1/25/12	ILS or LOC RWY 8L, Amdt 3B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3034	1/25/12	ILS or LOC RWY 8R, Amdt 59B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3035	1/25/12	ILS or LOC RWY 9L, Amdt 8B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3038	1/25/12	RNAV (RNP) Z RWY 8L, Orig-B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3039	1/25/12	RNAV (RNP) Z RWY 8R, Orig-B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3040	1/25/12	RNAV (GPS) Y RWY 27L, Amdt 3
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3041	1/25/12	RNAV (GPS) Y RWY 9L, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3042	1/25/12	RNAV (GPS) Y RWY 27R, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3043	1/25/12	RNAV (RNP) Z RWY 9L, Orig-B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3044	1/25/12	RNAV (RNP) Z RWY 27R, Orig-B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3045	2/1/12	ILS or LOC RWY 26L, Amdt 19B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3046	1/25/12	ILS or LOC RWY 10, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3047	1/25/12	ILS or LOC RWY 28, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3048	1/25/12	RNAV (GPS) Y RWY 8R, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3049	1/25/12	RNAV (GPS) Y RWY 26R, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3050	1/25/12	RNAV (RNP) Z RWY 28, Amdt 1
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3051	1/25/12	ILS or LOC RWY 26R, Amdt 5
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3052	2/1/12	RNAV (GPS) Y RWY 28, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3053	1/25/12	RNAV (GPS) Y RWY 26L, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3054	1/25/12	RNAV (GPS) Y RWY 8L, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3055	1/25/12	RNAV (GPS) Y RWY 9R, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3056	1/25/12	RNAV (RNP) Z RWY 26R, Orig-B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3057	1/25/12	ILS or LOC RWY 9R, Amdt 17B

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8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3058	1/25/12	RNAV (GPS) Y RWY 10, Amdt 2
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3059	1/25/12	RNAV (RNP) Z RWY 10, Amdt 1
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3060	1/25/12	ILS RWY 8L (CAT II), Amdt 3B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3061	1/25/12	RNAV (RNP) Z RWY 9R, Orig-B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3062	2/1/12	RNAV (RNP) Z RWY 27L, Amdt 1A
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3064	1/25/12	ILS RWY 26R (CAT II), Amdt 5
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3065	1/25/12	ILS RWY 9R (CAT II), Amdt 17B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3066	1/25/12	ILS RWY 8L (CAT III), Amdt 3B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3067	1/25/12	ILS RWY 9R (CAT III), Amdt 17B
8–Mar–12	NY	New York	John F Kennedy Intl	2/3068	1/25/12	ILS or LOC RWY 31L, Amdt 10B
8–Mar–12	NY	New York	John F Kennedy Intl	2/3070	1/25/12	ILS or LOC RWY 31R, Amdt 15A
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/3071	1/25/12	RNAV (RNP) Z RWY 26L, Orig-B
8–Mar–12	NY	New York	John F Kennedy Intl	2/3072	1/25/12	RNAV (GPS) Y RWY 22L, Amdt 1B
8–Mar–12	NY	New York	John F Kennedy Intl	2/3073	1/25/12	ILS RWY 22L (CAT III), Amdt 24A
8–Mar–12	NY	New York	John F Kennedy Intl	2/3074	1/25/12	ILS RWY 22R, Amdt 2
8–Mar–12	NY	New York	John F Kennedy Intl	2/3075	1/25/12	ILS or LOC RWY 22L, Amdt 24A
8–Mar–12	NY	New York	John F Kennedy Intl	2/3076	1/25/12	RNAV (RNP) Z RWY 22L, Orig-A
8–Mar–12	NY	New York	John F Kennedy Intl	2/3077	1/25/12	RNAV (GPS) RWY 22R, Amdt 1
8–Mar–12	NY	New York	John F Kennedy Intl	2/3089	1/25/12	ILS RWY 22L (CAT II), Amdt 24A
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3142	1/26/12	ILS or LOC RWY 23L, Amdt 8
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3143	1/26/12	RNAV (GPS) Y RWY 23L, Amdt 1
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3144	1/26/12	RNAV (RNP) Z RWY 23L, Amdt 1A
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3145	1/26/12	RNAV (RNP) Z RWY 5L, Amdt 1A
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3146	1/26/12	ILS or LOC RWY 23R, Amdt 11A
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3147	1/26/12	ILS or LOC RWY 5L, Amdt 5
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3148	1/26/12	RNAV (GPS) Y RWY 5L, Amdt 1
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3149	1/26/12	ILS or LOC RWY 5R, Amdt 27
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3150	1/26/12	RNAV (GPS) Y RWY 5R, Amdt 1
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3151	1/26/12	ILS RWY 23R (CAT II), Amdt 11A
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3152	1/26/12	ILS RWY 23R (CAT III), Amdt 11A
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3153	1/26/12	RNAV (GPS) Y RWY 23R, Amdt 1
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3155	1/26/12	RNAV (RNP) Z RWY 23R, Amdt 1A
8–Mar–12	NC	Raleigh/Durham	Raleigh-Durham Intl	2/3160	1/26/12	RNAV (RNP) Z RWY 5R, Amdt 1A
8–Mar–12	NC	Greensboro	Piedmont Triad Intl	2/3175	1/25/12	ILS RWY 23L (CAT II), Amdt 9A
8–Mar–12	NC	Greensboro	Piedmont Triad Intl	2/3176	1/25/12	RNAV (GPS) RWY 5R, Amdt 2A
8–Mar–12	NC	Greensboro	Piedmont Triad Intl	2/3177	1/25/12	ILS or LOC RWY 23L, Amdt 9A
8–Mar–12	NC	Greensboro	Piedmont Triad Intl	2/3178	1/25/12	RNAV (GPS) RWY 23L, Amdt 2A
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3231	1/17/12	ILS RWY 16R (CAT III), Amdt 1
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3232	1/17/12	RNAV (GPS) RWY 16C, Amdt 1B
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3233	1/17/12	ILS or LOC RWY 16L, Amdt 4A
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3234	1/17/12	ILS or LOC RWY 16R, Amdt 1
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3235	1/17/12	ILS RWY 16R (SA CAT I), Amdt 1
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3236	1/17/12	ILS RWY 16R (CAT II), Amdt 1
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3237	1/17/12	ILS or LOC RWY 16C, Amdt 13A
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3238	1/17/12	ILS RWY 16C (CAT II), Amdt 13A
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3239	1/17/12	ILS RWY 16L (CAT II), Amdt 4A
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3240	1/17/12	ILS RWY 16C (CAT III), Amdt 13A
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3241	1/17/12	ILS RWY 16L (CAT III), Amdt 4A
8–Mar–12	WA	Seattle	Seattle-Tacoma Intl	2/3242	1/17/12	RNAV (GPS) RWY 16L, Amdt 2B
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3243	1/26/12	ILS RWY 34L (CAT III), Amdt 2
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3244	1/26/12	ILS or LOC RWY 34R, Amdt 3
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3245	1/26/12	ILS RWY 16L (CAT III), Amdt 3
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3246	1/26/12	ILS or LOC/DME RWY 35, Amdt 3
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3250	1/26/12	ILS or LOC RWY 17, Amdt 13
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3251	1/27/12	RNAV (RNP) Z RWY 6R, Orig-A
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3252	1/27/12	ILS or LOC RWY 6R, Amdt 17A

AIRAC Date	State	City	Airport	FDC No.	FDC Date	Subject
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3253	1/26/12	ILS RWY 17 (SA CAT II), Amdt 13
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3254	1/26/12	ILS RWY 16R (CAT III), Amdt 3
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3256	1/26/12	ILS or LOC RWY 34L, Amdt 2
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3257	1/26/12	ILS or LOC RWY 16R, Amdt 3
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3258	1/26/12	ILS or LOC RWY 16L, Amdt 3
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3259	1/26/12	ILS RWY 16R (CAT II), Amdt 3
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3260	1/27/12	RNAV (GPS) Y RWY 6R, Amdt 1A
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3261	1/27/12	RNAV (RNP) Z RWY 7R, Orig-A
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3263	1/26/12	ILS RWY 34R (CAT II), Amdt 3
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3264	1/26/12	ILS RWY 34L (CAT II), Amdt 2
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3265	1/26/12	ILS RWY 16L (CAT II), Amdt 3
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3266	1/26/12	ILS RWY 34R (CAT III), Amdt 3
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3267	1/27/12	RNAV (RNP) Z RWY 7L, Orig-A
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3268	1/27/12	ILS or LOC RWY 7L, Amdt 7A
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3269	1/27/12	RNAV (RNP) Z RWY 6L, Orig-A
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3270	1/26/12	RNAV (GPS) RWY 34R, Orig-A
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3271	1/27/12	RNAV (GPS) Y RWY 7R, Amdt 2A
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3272	1/27/12	RNAV (GPS) Y RWY 7L, Amdt 2A
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3273	1/27/12	RNAV (GPS) Y RWY 6L, Amdt 1A
8–Mar–12	UT	Salt Lake City	Salt Lake City Intl	2/3274	1/26/12	ILS RWY 34R (SA CAT I), Amdt 3
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3275	1/27/12	ILS or LOC RWY 7R, Amdt 6B
8–Mar–12	CA	Los Angeles	Los Angeles Intl	2/3276	1/27/12	ILS or LOC RWY 6L, Amdt 12A
8–Mar–12	CO	Colorado Springs	City of Colorado Springs Muni.	2/3277	1/27/12	ILS RWY 17L (SA CAT I), Amdt 1
8–Mar–12	CO	Colorado Springs	City of Colorado Springs Muni.	2/3278	1/27/12	RNAV (GPS) Y RWY 17R, Amdt 2
8–Mar–12	CO	Colorado Springs	City of Colorado Springs Muni.	2/3279	1/27/12	ILS or LOC RWY 17L, Amdt 1
8–Mar–12	CO	Colorado Springs	City of Colorado Springs Muni.	2/3282	1/27/12	RNAV (RNP) Z RWY 17R, Orig-B
8–Mar–12	OR	Portland	Portland Intl	2/3291	1/17/12	ILS or LOC RWY 10L, Amdt 3B
8–Mar–12	OR	Portland	Portland Intl	2/3294	1/17/12	RNAV (GPS) RWY 10L, Amdt 1
8–Mar–12	OR	Portland	Portland Intl	2/3297	1/17/12	RNAV (GPS) RWY 28L, Amdt 1
8–Mar–12	OR	Portland	Portland Intl	2/3298	1/17/12	RNAV (GPS) RWY 10R, Amdt 1
8–Mar–12	OR	Portland	Portland Intl	2/3299	1/17/12	RNAV (GPS) RWY 28R, Amdt 1
8–Mar–12	OR	Portland	Portland Intl	2/3300	1/17/12	ILS or LOC RWY 28R, Amdt 14
8–Mar–12	AL	Montgomery	Montgomery Rgnl	2/3308	1/24/12	ILS or LOC RWY 28, Amdt 10
8–Mar–12	AL	Gadsden	Northeast Alabama Rgnl	2/3309	1/24/12	RNAV (GPS) RWY 6, Amdt 1
8–Mar–12	NC	Mount Airy	Mount Airy/Surry County	2/3310	1/24/12	NDB RWY 36, Orig-B
8–Mar–12	OR	Portland	Portland Intl	2/3327	1/17/12	ILS or LOC RWY 28L, Amdt 2
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3364	1/26/12	RNAV (RNP) Z RWY 25L, Orig-B
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3366	1/26/12	RNAV (GPS) Y RWY 26, Amdt 2
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3367	1/26/12	RNAV (GPS) Y RWY 25L, Amdt 1
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3368	1/26/12	RNAV (GPS) Y RWY 25R, Amdt 2A
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3369	1/26/12	ILS or LOC RWY 8, Orig-B
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3370	1/26/12	RNAV (RNP) Z RWY 25R, Orig-B
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3371	1/26/12	RNAV (RNP) Z RWY 7R, Orig-B
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3372	1/26/12	RNAV (RNP) Z RWY 26, Orig-B
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3373	1/26/12	ILS or LOC RWY 26, Orig-C
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3374	1/26/12	RNAV (RNP) Z RWY 7L, Orig-B
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/3377	1/26/12	RNAV (GPS) Y RWY 7L, Amdt 1
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/3537	1/24/12	RNAV (RNP) Z RWY 13R, Orig-D
8–Mar–12	NY	Montgomery	Orange County	2/3637	1/24/12	ILS or LOC RWY 3, Amdt 3B
8–Mar–12	TX	Dallas-Fort Worth	Dallas-Fort Worth Intl	2/3718	1/24/12	ILS or LOC RWY 13R, Amdt 8
8–Mar–12	MI	Kalamazoo	Kalamazoo/Battle Creek Intl	2/3973	1/24/12	RADAR–1, Amdt 9
8–Mar–12	MI	Kalamazoo	Kalamazoo/Battle Creek Intl	2/3974	1/24/12	RNAV (GPS) RWY 35, Orig
8–Mar–12	DC	Washington	Washington Dulles Intl	2/4178	1/26/12	ILS or LOC RWY 1R, Amdt 24
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/4185	1/25/12	ILS or LOC RWY 27R, Amdt 4A
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/4188	1/25/12	ILS or LOC RWY 27L, Amdt 16B
8–Mar–12	GA	Atlanta	Hartsfield-Jackson Atlanta Intl	2/4192	1/25/12	ILS RWY 27L (CAT II), Amdt 16B
8–Mar–12	OR	Portland	Portland Intl	2/5028	1/24/12	ILS RWY 10R (CAT III), Amdt 34
8–Mar–12	OR	Portland	Portland Intl	2/5029	1/24/12	ILS RWY 10R (CAT II), Amdt 34
8–Mar–12	OR	Portland	Portland Intl	2/5030	1/24/12	ILS or LOC RWY 10R, Amdt 34

AIRAC Date	State	City	Airport	FDC No.	FDC Date	Subject
8–Mar–12	OR	Portland	Portland Intl	2/5031	1/24/12	ILS RWY 10R (SA CAT I), Amdt 34
8–Mar–12	AZ	Phoenix	Phoenix Sky Harbor Intl	2/5642	1/27/12	RNAV (GPS) Y RWY 7R, Amdt 1

[FR Doc. 2012–3376 Filed 2–15–12; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Part 203

[Docket No. FR–5461–F–02]

RIN 2502–AJ01

Federal Housing Administration (FHA): Suspension of Section 238(c) Single-Family Mortgage Insurance in Military Impacted Areas

AGENCY: Office of the Assistant Secretary of Housing—Federal Housing Commissioner, HUD.

ACTION: Final rule.

SUMMARY: On August 30, 2011, HUD published a proposed rule to suspend FHA's mortgage insurance program for military impacted areas under section 238(c) of the National Housing Act. This single-family mortgage insurance program, established by regulation in 1977, has been significantly underutilized for the past several years. Additionally, these mortgage loans are insured under comparable terms and conditions as loans insured under HUD's primary single-family mortgage insurance program under section 203(b) of the National Housing Act. Accordingly, those borrowers who would be served under section 238(c) of the National Housing Act are served equally well under the section 203(b) mortgage insurance program. The suspension of this mortgage insurance program is consistent with the President's budget requests for Fiscal Years (FYs) 2011 and 2012. In this final rule, HUD is adopting the proposed rule without change.

DATES: *Effective Date:* March 19, 2012.

FOR FURTHER INFORMATION CONTACT: Karin Hill, Director, Office of Single Family Program Development, Office of Housing, Department of Housing and Urban Development, 451 7th Street SW., Room 9278, Washington, DC 20410–8000; telephone number 202–708–4308 (this is not a toll-free number). Persons with hearing or speech impairments may access this number via TTY by calling the Federal Relay Service at 1–800–877–8339.

SUPPLEMENTARY INFORMATION:

I. Background—The Proposed Rule

On August 30, 2011, HUD published a proposed rule in the **Federal Register** (76 FR 53851) to suspend FHA's mortgage insurance program for military impacted areas under section 238(c) of the National Housing Act (Act). Section 238(c) of the Act (12 U.S.C. 1715z–3(c)) was added by the Housing and Community Development Act of 1977 (Pub. L. 95–128) to authorize HUD to insure mortgages executed in connection with the construction, repair, rehabilitation, or purchase of property located near any installation of the Armed Forces of the United States in federally impacted areas in which conditions are such that one or more of the applicable insuring requirements under another single-family mortgage insurance program cannot be met.

HUD's current regulation implementing section 238(c) is codified at 24 CFR 203.43e. The regulation, promulgated in 1977, closely tracks the language of section 238(c) of the Act. Although established to ensure the availability of affordable housing in military impacted areas, the program has been minimally utilized by eligible borrowers. Section 238(c) mortgage insurance has been available in only six counties throughout the country, three in Georgia and three in New York. From January 1, 2005, to June 30, 2010, FHA insured 4,542 single-family home loans in these six counties, and only 2,309 were endorsed under section 238(c) of the Act. The 2,309 loans endorsed since 2005 represent only .05 percent of all FHA-insured loans endorsed during that span.

The President's budget requests for FYs 2011 and 2012 acknowledged the underutilization of the section 238(c) program and advised that HUD would take action to halt the availability of the program in light of the significant underutilization. The FY 2011 budget request found at *http://www.gpoaccess.gov/usbudget/fy11/index.html* states the following:

> The Budget assumes that HUD will administratively suspend the Section 238(c) program in 2011. The Section 238(c) program provides single family mortgage insurance similar to MMI for a small number of families in areas affected by military installations. The elimination of Section 238(c) will not negatively impact the availability of FHA insured financing in the six counties currently covered under this program. (See HUD Appendix to the Budget at page 620 at *http://www.gpoaccess.gov/usbudget/fy11/appendix.html*).[1]

II. This Final Rule

This final rule follows publication of the August 30, 2011, proposed rule. The proposed rule provided for a 60-day public comment period, which closed on October 31, 2011. HUD did not receive any public comments, and HUD is adopting as final the proposed August 30, 2011, rule without change.

Consistent with the President's budget request and Executive Order (EO) 13563, entitled ''Improving Regulation and Regulatory Review,'' signed by the President on January 18, 2011, and published on January 21, 2011, at 76 FR 3821, this final rule suspends the section 238(c) program and removes § 203.43e from HUD's codified regulations. HUD's removal of the regulations at § 203.43e is not inconsistent with suspension of the section 238(c) mortgage insurance program. If HUD subsequently determines that there is a demand for this program and that military families would be better served by this program, HUD can reactivate it on the basis of the statutory language and does not need a regulation to make insurance available under this program. If such a situation occurs, HUD would notify the public through **Federal Register** notice that the program has been activated, so that eligible borrowers would be able to inquire about the availability of insurance under this program from their lenders. HUD notes that the removal of the regulations at § 203.43e would have no impact on loans already endorsed for FHA insurance under the section 238(c) program.

III. Findings and Certification

Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements, unless the agency certifies that the rule will not have a significant

[1] The President's Budget for FY 2012, found at *http://www.whitehouse.gov/omb/budget/Overview*, contains identical language to the paragraph cited above; see the HUD Appendix to the FY 2012 Budget on page 591.

economic impact on a substantial number of small entities.

The final rule would not modify or add any new regulatory burdens on FHA-approved mortgage lenders. Rather, the final rule would remove § 203.43e from HUD's regulations, in conformity to HUD's (and the Administration's) decision to no longer exercise its authority to insure mortgages under section 238(c) of the Act. As more fully discussed above in the preamble to this rule, the mortgage insurance authority provided by section 238(c) of the Act has been minimally sought by eligible borrowers and consequently minimally utilized by lenders and other small entities participating in the FHA programs. Further, as noted above, section 238(c) mortgage insurance operated in a manner comparable to FHA's mortgage insurance program under section 203(b) of the Act, HUD's primary single-family mortgage insurance program.

Accordingly, for the above reasons, the undersigned certifies that this rule will not have a significant economic impact on a substantial number of small entities.

Executive Order 13132, Federalism

Executive Order 13132 (entitled ''Federalism'') prohibits an agency from publishing any rule that has federalism implications if the rule either imposes substantial direct compliance costs on state and local governments and is not required by statute, or the rule preempts state law, unless the agency meets the consultation and funding requirements of section 6 of the Executive Order. This rule will not have federalism implications and would not impose substantial direct compliance costs on state and local governments or preempt state law within the meaning of the Executive Order.

Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (2 U.S.C.1531–1538) (UMRA) establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments, and on the private sector. This rule does not impose any federal mandates on any state, local, or tribal governments, or on the private sector, within the meaning of UMRA.

Environmental Impact

This final rule does not direct, provide for assistance or loan and mortgage insurance for, or otherwise govern or regulate, real property acquisition, disposition, leasing, rehabilitation, alteration, demolition, or new construction, or establish, revise, or provide for standards for construction or construction materials, manufactured housing, or occupancy. Accordingly, under 24 CFR 50.19(c)(1), this rule is categorically excluded from environmental review under the National Environmental Policy Act of 1969 (42 U.S.C. 4321).

Catalogue of Federal Domestic Assistance

The Catalogue of Federal Domestic Assistance Number for the principal FHA single-family mortgage insurance program is 14.117.

List of Subjects in 24 CFR Part 203

Hawaiian Natives, Home improvement, Indians—lands, Loan programs—housing and community development, Mortgage insurance, Reporting and recordkeeping requirements, Solar energy.

Accordingly, for the reasons discussed in the preamble, 24 CFR part 203 is amended as follows:

PART 203—SINGLE FAMILY MORTGAGE INSURANCE

■ 1. The authority citation for part 203 continues to read as follows:

Authority: 12 U.S.C. 1709, 1710, 1715b, 1715z–16, and 1715u; 42 U.S.C. 3535(d).

■ 2. Remove and reserve § 203.43e.

Dated: February 10, 2012.

Carol J. Galante,

Acting Assistant Secretary for Housing—Federal Housing Commissioner.

[FR Doc. 2012–3667 Filed 2–15–12; 8:45 am]

BILLING CODE 4210–67–P

Proposed Rules

Federal Register

Vol. 77, No. 32

Thursday, February 16, 2012

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

DEPARTMENT OF THE INTERIOR

National Indian Gaming Commission

25 CFR Parts 524, 539, 577, 580, 581, 582, 583, 584, and 585

RIN 3141–AA47

Appeal Proceedings Before the Commission

AGENCY: National Indian Gaming Commission, Interior.

ACTION: Proposed rule; correction.

SUMMARY: This document corrects the preamble and regulatory text of the proposed rule published in the **Federal Register** on January 31, 2012, with respect to appeal proceedings before the National Indian Gaming Commission.

FOR FURTHER INFORMATION CONTACT: Maria Getoff, (202) 632–7003.

SUPPLEMENTARY INFORMATION: This document makes six technical corrections in the proposed rule to clarify that the definition of ''summary proceeding'' in proposed § 580.1 applies only to ordinance and management contract appeals and that the definition of ''limited participant'' applies only to appeals of disapprovals of gaming ordinances. Section 581.4 is corrected to reference all appeal actions listed in part 584. This notice corrects a typographical error in § 585.3(a) by replacing ''§ 585.7 with ''§ 585.6'', and clarifies that service of the record will be accomplished after a notice of appeal in proposed § 585.6. Finally, this correction removes limited participant from § 585.7(b) so that the proposed rule is consistent with part 585 and the definition of limited participant. This notice makes technical corrections to the preamble so that the preamble is consistent with the proposed rule.

Correction

In the preamble to proposed rule FR Doc. 2012–1767, beginning on page 4720 in the issue of January 31, 2012, make the following corrections in the **SUPPLEMENTARY INFORMATION** section:

1. On page 4723 in the 1st column, second full paragraph remove ''a notice of appeal and brief'' and add in its place ''an appeal brief''.

2. On page 4724 in the 1st column remove the first full paragraph.

3. On page 4724 in the 1st column, fifth full paragraph, remove ''a notice of appeal and appeal brief'' and add in its place ''an appeal brief''.

In proposed rule FR Doc. 2012–1767, beginning on page 4720 in the issue of January 31, 2012, make the following corrections to the amendatory text:

1. On page 4725 in the 1st column, in § 580.1:

a. In the definition of ''limited participant'' remove the word ''either'' between the words ''in'' and ''an'' and remove ''or an appeal on written submissions under 585.5''; and

b. Revise the definition of ''summary proceeding''.

The revision reads as follows:

§ 580.1 What definitions apply?

* * * * *

Summary proceeding. Ordinance appeals and management contract and amendment appeals are summary proceedings.

§ 581.4 [Corrected]

2. On page 4726, in the 2nd column, in § 581.4, add ''the Commission's proposal to remove a certificate of self-regulation,'' after the word, ''contracts,''.

§ 585.3 [Corrected]

3. On page 4730, in the 2nd column, in § 585.3(a), remove ''§ 585.7'' and add in its place ''§ 585.6''.

§ 585.6 [Corrected]

5. On page 4731, in the 1st column, in § 585.6, remove the following text, ''an appeal brief'' and add in its place, ''a notice of appeal''.

§ 585.7 [Corrected]

6. On page 4731, in the 1st column, in § 585.7(b), remove '', and any limited participant''.

Dated: February 10, 2012, in Washington, DC.

Maria Getoff,

Senior Attorney.

[FR Doc. 2012–3559 Filed 2–15–12; 8:45 am]

BILLING CODE 7565–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

42 CFR Parts 401 and 405

[CMS–6037–P]

RIN 0938–AQ58

Medicare Program; Reporting and Returning of Overpayments

AGENCY: Centers for Medicare & Medicaid Services (CMS), HHS.

ACTION: Proposed rule.

SUMMARY: This proposed rule would require providers and suppliers receiving funds under the Medicare program to report and return overpayments by the later of the date which is 60 days after the date on which the overpayment was identified; or any corresponding cost report is due, if applicable.

DATES: To be assured consideration, comments must be received at one of the addresses provided below, no later than 5 p.m. on April 16, 2012.

ADDRESSES: In commenting, please refer to file code CMS–6037–P. Because of staff and resource limitations, we cannot accept comments by facsimile (FAX) transmission.

You may submit comments in one of four ways (please choose only one of the ways listed):

1. *Electronically.* You may submit electronic comments on this regulation to *http://www.regulations.gov.* Follow the ''Submit a comment'' instructions.

2. *By regular mail.* You may mail written comments to the following address only: Centers for Medicare & Medicaid Services, Department of Health and Human Services, Attention: CMS–6037–P, P.O. Box 8013, Baltimore, MD 21244–8013.

Please allow sufficient time for mailed comments to be received before the close of the comment period.

3. *By express or overnight mail.* You may send written comments to the following address only: Centers for Medicare & Medicaid Services, Department of Health and Human Services, Attention: CMS–6037–P, Mail Stop C4–26–05, 7500 Security Boulevard, Baltimore, MD 21244–1850.

4. *By hand or courier.* If you prefer, you may deliver (by hand or courier)

your written comments before the close of the comment period to either of the following addresses:

a. For delivery in Washington, DC—

Centers for Medicare & Medicaid Services, Department of Health and Human Services, Room 445–G, Hubert H. Humphrey Building, 200 Independence Avenue SW., Washington, DC 20201.

(Because access to the interior of the Hubert H. Humphrey Building is not readily available to persons without Federal government identification, commenters are encouraged to leave their comments in the CMS drop slots located in the main lobby of the building. A stamp-in clock is available for persons wishing to retain a proof of filing by stamping in and retaining an extra copy of the comments being filed.)

b. For delivery in Baltimore, MD—

Centers for Medicare & Medicaid Services, Department of Health and Human Services, 7500 Security Boulevard, Baltimore, MD 21244–1850.

If you intend to deliver your comments to the Baltimore address, please call telephone number (410) 786–1066 in advance to schedule your arrival with one of our staff members.

Comments mailed to the addresses indicated as appropriate for hand or courier delivery may be delayed and received after the comment period.

Submission of comments on paperwork requirements. You may submit comments on this document's paperwork requirements by following the instructions at the end of the ''Collection of Information Requirements'' section in this document.

For information on viewing public comments, see the beginning of the **SUPPLEMENTARY INFORMATION** section.

FOR FURTHER INFORMATION CONTACT: Tiana Korley, (410) 786–9702.

SUPPLEMENTARY INFORMATION:

Inspection of Public Comments: All comments received before the close of the comment period are available for viewing by the public, including any personally identifiable or confidential business information that is included in a comment. We post all comments received before the close of the comment period on the following Web site as soon as possible after they have been received: *http://www.regulations.gov*. Follow the search instructions on that Web site to view public comments.

Comments received timely will also be available for public inspection as they are received, generally beginning approximately 3 weeks after publication of a document, at the headquarters of the Centers for Medicare & Medicaid Services, 7500 Security Boulevard, Baltimore, Maryland 21244, Monday through Friday of each week from 8:30 a.m. to 4 p.m. To schedule an appointment to view public comments, phone 1–800–743–3951.

I. Background

The Medicare program (title XVIII of the Social Security Act (the Act)) is the primary payer of health care for approximately 47 million enrolled beneficiaries. Providers and suppliers furnishing Medicare items and services must comply with the Medicare requirements set forth in the Act and in our regulations. The requirements are meant to ensure compliance with applicable statutes, promote the furnishing of high quality care, and to protect the Medicare Trust Funds against fraud and improper payments. As Medicare spending has grown, we have increased our efforts to reduce fraud, waste, and abuse in the Medicare program.

As part of these efforts we have twice proposed—but did not finalize—rules that would have amended our regulations related to Medicare overpayments. (See the March 25, 1998 (63 FR 14506) and January 25, 2002 (67 FR 3662) proposed rules.)

On March 23, 2010, the Patient Protection and Affordable Care Act (Pub. L. 111–148) was enacted. The Health Care Education Reconciliation Act of 2010 (Pub. L. 111–152) then amended certain provisions of Public Law 111–148. These public laws are collectively known as the Affordable Care Act. The Affordable Care Act makes a number of changes to the Medicare program that enhance our efforts to recover overpayments and combat fraud, waste and abuse in the Medicare program.

Section 6402(a) of the Affordable Care Act established a new section 1128J(d) of the Act entitled ''Reporting and Returning of Overpayments.'' Section 1128J(d)(1) of the Act requires a person who has received an overpayment to report and return the overpayment to the Secretary, the State, an intermediary, a carrier, or a contractor, as appropriate, at the correct address, and to notify the Secretary, State, intermediary, carrier or contractor to whom the overpayment was returned in writing of the reason for the overpayment. Section 1128J(d)(2) of the Act requires that an overpayment be reported and returned by the later of—(1) the date which is 60 days after the date on which the overpayment was identified; or (2) the date any corresponding cost report is due, if applicable. Section 1128J(d)(3) of the Act specifies that any overpayment retained by a person after the deadline for reporting and returning an overpayment is an obligation (as defined in 31 U.S.C. 3729(b)(3)) for purposes of 31 U.S.C. 3729.

Section 1128J(d)(4)(A) defines ''knowing'' and ''knowingly'' as those terms are defined in 31 U.S.C. 3729(b); the terms ''knowing'' and ''knowingly'' ''mean that a person with respect to information—(i) has actual knowledge of the information; (ii) acts in deliberate ignorance of the truth or falsity of the information; or (iii) acts in reckless disregard of the truth or falsity of the information.'' There need not be ''proof of specific intent to defraud.'' Section 1128J(d)(4)(B) of the Act defines the term ''overpayment'' as any funds that a person receives or retains under title XVIII or XIX to which the person, after applicable reconciliation, is not entitled under such title. Finally, section 1128J(d)(4)(C) of the Act defines the term ''person'' as a provider of services, supplier, Medicaid managed care organization (MCO) (as defined in section 1903(m)(1)(A) of the Act), Medicare Advantage organization (MAO) (as defined in section 1859(a)(1) of the Act) or PDP sponsor (PDP) (as defined in section 1860D–41(a)(13) of the Act) but the definition does not include a beneficiary.

II. Provisions of the Proposed Regulation

To implement section 6402(a) of the Affordable Care Act, we propose establishing a new subpart D in Part 401 of our regulations. In this section, we outline the content of the proposed provisions of this new subpart D.

A. Scope of Subpart (Proposed § 401.301)

In proposed § 401.301, we state that subpart D sets forth the policies and procedures for reporting and returning overpayments to the Medicare program for providers and suppliers of services under Parts A and B of title XVIII. At this time, we are proposing to implement the requirements set forth in section 1128J(d) of the Act only as they relate to Medicare Part A and Part B providers and suppliers. Other stakeholders, including, without limitation, MAOs, PDPs, and Medicaid MCOs will be addressed at a later date.

Notwithstanding the foregoing, we remind all stakeholders that even without a final regulation they are subject to the statutory requirements found in section 1128J(d) of the Act and could face potential False Claims Act liability, Civil Monetary Penalties Law liability, and exclusion from Federal health care programs for failure to report and return an overpayment. Additionally, providers and suppliers continue to be obliged to comply with our current procedures when we, or our contractors, determine an overpayment and issue a demand letter.

B. Definitions (Proposed § 401.303)

For purposes of this subpart only, we propose the following definitions:

1. Overpayment

Section 1128J(d) of the Act provides that an overpayment means ''* * * any funds that a person receives or retains under title XVIII * * * to which the person, after applicable reconciliation, is not entitled under such title.'' In § 401.303, we propose to include this same definition in our proposed rule. Examples of overpayments under this proposed definition could include all of the following:

- Medicare payments for noncovered services.
- Medicare payments in excess of the allowable amount for an identified covered service.
- Errors and nonreimbursable expenditures in cost reports.
- Duplicate payments.
- Receipt of Medicare payment when another payor had the primary responsibility for payment.

In certain circumstances, Medicare makes estimated payments for services with the knowledge that a reconciliation of those payments to actual costs will be done when the actual costs or related information becomes available, usually at a later date. Interim payments made to a provider throughout the cost year are reconciled with covered and reimbursable costs at the time the cost report is due. The statutory and proposed regulatory definition of the term overpayment acknowledges this practice and provides that an overpayment does not exist until after an applicable reconciliation takes place. When a provider files a cost report, the provider is attesting to the accuracy of the information contained on the cost report and must maintain the appropriate documentation supporting the costs that are claimed on the cost report. We rely upon the information that providers submit through the cost report and we believe that providers must accurately report any overpayments at the time they submit any cost reports to CMS—whether it is an initial submission of a cost report or an amended one.

2. Medicare Contractor

We propose that the term ''Medicare contractor'' means a fiscal intermediary, carrier, durable medical equipment Medicare administrative contractor (DME MAC), or Part A/Part B Medicare administrative contractor. We believe that this proposed definition captures the different contractors that would be involved in receiving reports of overpayments as well as handling the return of overpayments, consistent with the statutory requirement.

3. Person

We propose that a person means a provider (as defined in § 400.202) or supplier (as defined in § 400.202). This definition does not include a beneficiary. Our proposal is consistent with the definition of a ''person'' in section 1128J(d) of the Act.

C. Requirements for Reporting and Returning of Overpayments (Proposed § 401.305)

1. General

Section 1128J of the Act provides that if a person has received an overpayment, the person shall ''(i) report and return the overpayment to the Secretary * * * an intermediary, a carrier, or a contractor, as appropriate, at the correct address; and (ii) notify the Secretary * * * intermediary, carrier, or contractor to whom the overpayment was returned in writing of the reason for the overpayment.''

We propose to implement these requirements by using the existing voluntary refund process, which will be renamed the ''self-reported overpayment refund process.'' This process is described in Publication 100–06, Chapter 4 of the Medicare Financial Management Manual. Under the existing voluntary refund process, providers and suppliers report overpayments using a form that each Medicare contractor makes available on its Web site. The form requires that providers and suppliers provide information to allow CMS to identify the affected claims, such as the health insurance claim number (HICN); the provider's or supplier's name, number and tax identification number; and the date of service. The voluntary refund process also requires providers and suppliers to summarize why the refund is being made including the following information: (1) How the error was discovered; (2) a description of the corrective action plan implemented to ensure the error does not occur again; (3) the reason for the refund; (4) whether the provider or supplier has a corporate integrity agreement (CIA) with the OIG or is under the OIG Self-Disclosure Protocol; (5) the timeframe and the total amount of refund for the period during which the problem existed that caused the refund; (6) Medicare claim control number, as appropriate; (7) Medicare National Provider Identification (NPI) number; (8) a refund in the amount of the overpayment; and (9) if a statistical sample was used to determine the overpayment amount, description of the statistically valid methodology used to determine the overpayment. We are proposing that providers and suppliers would be required to use the self-reported overpayment refund process set forth by the applicable Medicare contractor to report and return overpayments.

Some clarification may be helpful in defining potential reasons for an overpayment since such information must be reported under section 1128J(d) of the Act. While we cannot provide an exhaustive list of all potential reasons for the overpayment as required to be reported at § 401.305(d), we can provide examples. Examples of what a person may report as the reason for the overpayment include the following: (1) Incorrect service date; (2) duplicate payment; (3) incorrect CPT code; (4) insufficient documentation; and (5) lack of medical necessity. We note that many of the forms currently available from our contractors provide a ''check the box'' format that allows providers and suppliers to easily identify the reason for the overpayment. For overpayments that are not listed on the form that is available from the Medicare contractor, there is an associated ''other'' box that allows providers and suppliers to clarify the reason for the overpayment.

We make these proposals because we believe that the information requested under the existing voluntary refund process, such as the date of service and the HICN, is necessary to allow CMS to appropriately match claims information with the information that is reported by the provider or supplier and to understand the nature of the overpayment. Furthermore, we recognize that the reporting forms may differ among the different Medicare contractors and plan to develop a uniform reporting form that will enable all overpayments to be reported and returned in a consistent manner across all Medicare contractors. Until such uniform reporting form is made available, providers and suppliers should utilize the existing form available from the Web site of the applicable Medicare contractor as discussed earlier in this proposed rule.

2. Identified

Section 1128J of the Act provides that the terms 'knowing' and 'knowingly' have the meaning given those terms in the False Claims Act (31 U.S.C. 3729(b)(3)). The statutory text, however, does not use this phrase other than in the definitions. In § 401.305 (a)(2), we propose that a person has identified an overpayment if the person has actual knowledge of the existence of the overpayment or acts in reckless disregard or deliberate ignorance of the overpayment. We believe Congress' use of the term ''knowing'' in the ACA was intended to apply to determining when a provider or supplier has identified an overpayment. We believe defining ''identification'' in this way gives providers and suppliers an incentive to exercise reasonable diligence to determine whether an overpayment exists. Without such a definition, some providers and suppliers might avoid performing activities to determine whether an overpayment exists, such as self-audits, compliance checks, and other additional research.

3. Reporting and Returning Deadlines

Section 1128J of the Act provides that an overpayment must be reported and returned by the later of—(i) the date which is 60 days after the date on which the overpayment was identified; or (ii) the date any corresponding cost report is due, if applicable. Proposed § 401.305(b) contains an identical requirement. If an overpayment is claims related, the provider or supplier would be required to report and return the overpayment within 60 days of identification. However, for those providers that submit cost reports, if the overpayment is such that it would generally be reconciled on the cost report by the provider, the provider would be permitted to report and return the overpayment either 60 days from the identification of the overpayment or on the date the cost report is due, whichever is later. For example, issues involving upcoding must be reported and returned within 60 days of identification because the upcoded claims for payment are not submitted to Medicare in the form of cost reports. However, for an overpayment that would generally be reconciled on the cost report, such as overpayments related to graduate medical education payments, the provider must report and return the overpayment either 60 days after it has been identified or on the date the cost report is due, whichever is later. We believe that the qualifying language ''if applicable'' supports the proposed approach of only permitting providers to rely upon the cost report deadline when relevant to the determination of whether an actual overpayment exists. We make this clarification to avoid situations in which providers improperly delay reporting and returning a claims-related, identified overpayment until the date a cost report is due. We do not believe that Congress intended to create a loophole that would allow providers to delay reporting and returning an identified overpayment until a cost report is due if the overpayment would not ordinarily be reconciled on the cost report.

The proposed 60-day requirement to report and return overpayments would run from the date on which the person had identified the overpayment. As previously discussed, an overpayment has been identified at the time that a person acts with actual knowledge of, in deliberate ignorance of, or with reckless disregard to the overpayment's existence. In some cases, a provider or supplier may receive information concerning a potential overpayment that creates an obligation to make a reasonable inquiry to determine whether an overpayment exists. If the reasonable inquiry reveals an overpayment, the provider then has 60 days to report and return the overpayment. On the other hand, failure to make a reasonable inquiry, including failure to conduct such inquiry with all deliberate speed after obtaining the information, could result in the provider knowingly retaining an overpayment because it acted in reckless disregard or deliberate ignorance of whether it received such an overpayment. For example, a provider that receives an anonymous compliance hotline telephone complaint about a potential overpayment has incurred an obligation to timely investigate that matter. If the provider diligently conducts the investigation, and reports and returns any resulting overpayments within the 60-day reporting and repayment period, then the provider would have satisfied its obligations under the proposed rule. If, however, the provider fails to make any reasonable inquiry into the complaint, the provider may be found to have acted in reckless disregard or deliberate ignorance of any overpayment.

In order to assist providers and suppliers with understanding when an overpayment has been identified, we provide the following examples:

- A provider of services or supplier reviews billing or payment records and learns that it incorrectly coded certain services, resulting in increased reimbursement.
- A provider of services or supplier learns that a patient death occurred prior to the service date on a claim that has been submitted for payment.
- A provider of services or supplier learns that services were provided by an unlicensed or excluded individual on its behalf.
- A provider of services or supplier performs an internal audit and discovers that overpayments exist.
- A provider of services or supplier is informed by a government agency of an audit that discovered a potential overpayment, and the provider or supplier fails to make a reasonable inquiry. (When a government agency informs a provider or supplier of a potential overpayment, the provider or supplier has an obligation to accept the finding or make a reasonable inquiry. If the provider's or supplier's inquiry verifies the audit results, then it has identified an overpayment and, assuming there is no applicable cost report, has 60 days to report and return the overpayment. As noted previously, failure to make a reasonable inquiry, including failure to conduct such inquiry with all deliberate speed after obtaining the information, could result in the provider or supplier knowingly retaining an overpayment because it acted in reckless disregard or deliberate ignorance of whether it received such an overpayment).
- A provider of services or supplier experiences a significant increase in Medicare revenue and there is no apparent reason—such as a new partner added to a group practice or a new focus on a particular area of medicine—for the increase. Nevertheless, the provider or supplier fails to make a reasonable inquiry into whether an overpayment exists. (When there is reason to suspect an overpayment, but a provider or supplier fails to make a reasonable inquiry into whether an overpayment exists, it may be found to have acted in reckless disregard or deliberate ignorance of any overpayment.)

We emphasize that these examples are not an exhaustive list of situations where a person has identified an overpayment.

We recognize that there are also intersections between the obligation to report and return overpayments under section 6402(a) of the Affordable Care Act and the existing procedures for providers and suppliers to self-disclose actual or potential violations of the physician self-referral statute to CMS through the Medicare Self-Referral Disclosure Protocol (SRDP). Providers and suppliers self-disclose violations under the SRDP with the intention of resolving overpayment liability exposure for the identified conduct. The SRDP is available on the CMS Web site at *https://www.cms.gov/PhysicianSelfReferral/Downloads/6409_SRDP_Protocol.pdf.* Under the SRDP, we may reduce the amount due and owing for violations of the physician self-referral statute. We have suspended the obligation to return overpayments under section 6402(a) of the Affordable Care Act when we acknowledge receipt of a disclosure made pursuant to the process established by the SRDP. Because the SRDP only suspends the running of the 60-day deadline to return a physician self-referral-related overpayment, the provider or supplier would be obligated still to report the overpayment using the process that we are proposing in § 401.305(a)(1). Specifically with regard to the SRDP, we seek comment on alternative approaches that would allow providers and suppliers to avoid making multiple reports of identified overpayments.

We note that there are also intersections between the obligation to report and return an overpayment under section 6402(a) of the Affordable Care Act and the existing procedures for reporting self-discovered evidence of potential fraud to the OIG through the OIG Self-Disclosure Protocol (OIG SDP). The OIG SDP is available on the OIG Web site at *http://oig.hhs.gov/authorities/docs/selfdisclosure.pdf.* Disclosures resolved through the OIG SDP result in a settlement with OIG that releases the OIG's applicable Civil Monetary Penalties Law (CMPL) and permissive exclusion authorities in exchange for a negotiated monetary payment that includes the overpayment as well as certain penalties and assessments. In § 401.305(b), we propose to suspend the obligation to return overpayments under section 6402(a) of the Affordable Care Act when OIG acknowledges receipt of a submission to the OIG SDP. The obligation to return overpayments consistent with the processes established in this proposed rule would be suspended until a settlement agreement is entered, or the provider or supplier withdraws or is removed from the OIG SDP. We also propose that once the provider or supplier notifies OIG of the identified overpayment through the OIG SDP, such notice would constitute a report for purposes of the reporting requirement set forth at § 401.305 of this proposed rule. However, we note that such reports must be made in accordance with the timeliness requirements set forth at § 401.305.

Providers and suppliers should ensure that they are using the most appropriate process to report and return overpayments. In the October 30, 1998 **Federal Register**, (63 FR 58400) the OIG published a notice stating—

> [the SDP] is intended to facilitate the resolution of only matters that, in the provider's reasonable assessment, are potentially violative of Federal, criminal, civil or administrative laws. Matters exclusively involving overpayments or errors that do not suggest that violations of law have occurred should be brought directly to the attention of the entity (e.g. a contractor such as a carrier or an intermediary) that processes claims and issues payment on behalf of the Government agency responsible for the particular Federal health care program (e.g., [CMS] for matters involving Medicare). The program contractors are responsible for processing the refund and will review the circumstances surrounding the initial overpayment. If the contractor concludes that the overpayment raises concerns about the integrity of the provider, the matter may be referred to the OIG. Accordingly, the provider's initial decision of where to refer a matter involving non-compliance with program requirements should be made carefully.

We believe the distinctions drawn previously are relevant because the process of reporting and returning overpayments pursuant to section 1128J of the Act cannot resolve any potential False Claims Act or OIG administrative liability associated with the overpayment (even though returning an overpayment may, among other benefits, limit any FCA or administrative liability arising from the retention of an overpayment). Providers and suppliers should be aware that the contractors will scrutinize overpayments received through this process and may make referrals to OIG whenever the contractors believe circumstances warrant such a referral.

We are aware that providers and suppliers may be concerned about scenarios in which they have identified an overpayment but because of the magnitude of the overpayment, need additional time to make repayment. Providers and suppliers may not delay the identification date in these situations to meet the deadline prescribed for reporting and returning the overpayment. Instead, if a provider or supplier needs additional time due to financial constraints, the provider or supplier must use the existing Extended Repayment Schedule (ERS) [1] process that is outlined in Publication 100–06, Chapter 4 of the Financial Management Manual. Because the statute is clear as to the deadline for reporting and returning overpayments, we believe that using the existing ERS process would be the best means of addressing potential financial limitations associated with the ability to repay the overpayment. We note that requests for ERS are not automatically granted and that providers and suppliers seeking to repay an identified overpayment using the ERS are required to submit significant documentation to allow CMS to verify that timely repayment of the overpayment represents a true financial hardship to the provider or supplier. The ERS is the only means by which extended repayment of an overpayment will be permitted. We propose to amend the definition of ''hardship'' at § 401.607 to ensure that providers and suppliers can seek to utilize the ERS to return identified overpayments for purposes of section 1128J(d) of the Act when financial constraints suggest that use of the ERS is appropriate.

Finally, we note the following with regard to overpayments that arise due to a violation of the anti-kickback statute (section 1128B(b)(1) and (2) of the Act). Compliance with the anti-kickback statute is a condition of payment. Claims that include items and services resulting from a violation of this law are not payable and constitute false or fraudulent claims for purposes of the False Claims Act. We recognize that, in many instances, a provider or supplier is not a party to, and is unaware of the existence of, an arrangement between third parties that causes the provider or supplier to submit claims that are the subject of a kickback. For example, a hospital may be unaware that a device manufacturer has paid a kickback to a physician on the hospital's medical staff to induce the physician to implant the manufacturer's device in procedures performed at the hospital. Moreover, even if a provider or supplier becomes aware of a potential third party payment arrangement, it would generally not be able to evaluate whether the payment was an illegal kickback or whether one or both parties had the requisite intent to violate the anti-kickback statute.

For this reason, we believe that providers who are not a party to a kickback arrangement are unlikely in most instances to have ''identified'' the overpayment that has resulted from the kickback arrangement and would therefore have no duty to report it or, as discussed later in this section, to repay it. To the extent that a provider or supplier who is not a party to a kickback arrangement has sufficient knowledge of the arrangement to have identified the resulting overpayment, the provider or supplier must report the overpayment to CMS in accordance with section 1128J(d) of the Act and corresponding

[1] The ''Extended Repayment Schedule'' was formerly referred to as the ''Extended Repayment Plan.''

regulations. Although the government may always seek repayment of claims paid that do not satisfy a condition of payment, where a kickback arrangement exists, HHS's enforcement efforts would most likely focus on holding accountable the perpetrators of that arrangement. Accordingly, we would refer the reported overpayment to OIG for appropriate action and would suspend the repayment obligation until the government has resolved the kickback matter (either by determining that no enforcement action is warranted or by obtaining a judgment, verdict, conviction, guilty plea, or settlement). Thus, if the provider has not identified the kickback or if it reported it when it did identify the kickback, our expectation is that only the parties to the kickback scheme would be required to repay the overpayment that was received by the innocent provider or supplier, except in the most extraordinary circumstances.

4. Applicable Reconciliation

As previously noted, the statutory and our proposed regulatory definition of an overpayment acknowledges that, in some instances, we make interim payments to a provider through the cost year and that the provider reconciles these payments with covered and reimbursable costs at the time the cost report is due. In § 401.305(c), we propose that ''applicable reconciliation'' will occur with the provider's submission of a cost report. We believe that this would include an initial cost report submission or an amended cost report. We expect providers to accurately report and return overpayments at these points in time, because we rely upon the information that providers include on cost reports.

We propose to recognize two exceptions to the general rule that the applicable reconciliation occurs with the provider's submission of a cost report. The first exception is related to Supplemental Security Income (SSI) ratios used in the calculation of disproportionate share hospital (DSH) payment adjustment. We publish these ratios annually on our Web site and providers are expected to use the appropriate ratio when submitting the cost report for that cost year, unless the published ratios are not available at the time the cost report is due. In instances where the provider later receives more recent information regarding its SSI ratio, we propose that the provider would not be required to amend the cost report or calculate the change in reimbursement and return the potential overpayment until the final reconciliation of the provider's cost report occurs. The second exception is related to the outlier reconciliation. We perform an outlier reconciliation at the time the cost report is settled if certain thresholds are exceeded. Prior to this reconciliation the actual amount of any overpayment is not known. In instances where the provider is aware it has exceeded the established thresholds and an outlier reconciliation will be performed, we propose that the provider would not be required to estimate the change in reimbursement and return the estimated overpayment until the final settlement of that cost report.

5. Enforcement

Section 1128J(d) of the Act provides that any overpayment retained by a person after the deadline for reporting and returning the overpayment is an obligation for purposes of 31 U.S.C. 3729. Any person who ''knowingly conceals or knowingly and improperly avoids or decreases an obligation to pay or transmit money or property to the Government'' may be found liable under the False Claims Act. (See 31 U.S.C. 3729 et seq.) Proposed § 401.305(f) contains a similar statement. Additionally, any person who ''knows of an overpayment [as defined in section 1128J(d)(4) of the Act] and does not report and return the overpayment in accordance with such section'' may be found liable under the Civil Monetary Penalties Law (section 1128A(a)(10) of the Act) and accordingly could be excluded from participation in Federal health care programs (section 1128A of the Act).

6. Lookback Period and Related Issues

In § 401.305(g), we are proposing that overpayments must be reported and returned only if a person identifies the overpayment within 10 years of the date the overpayment was received. We selected 10 years because this is the outer limit of the False Claims Act statute of limitations. We believe that the proposed 10-year lookback period is appropriate for several reasons. First, we believe that providers and suppliers should have certainty after a reasonable period that they can close their books and not have ongoing liability associated with an overpayment. We also believe that the length of the lookback period is long enough to sufficiently further our interest in ensuring that overpayments are timely returned to the Medicare Trust Funds.

We propose to amend the reopening rules at § 405.980(b) to provide that overpayments reported in accordance with § 401.305 may be reopened for a period of 10 years. We make this proposal in order to ensure that our reopening regulations are consistent with the lookback period that we are proposing. We seek comment on the proposed 10-year lookback period. In addition, we seek comment on our proposal to amend the reopening rules to provide for a 10-year reopening period.

III. Collection of Information Requirements

Under the Paperwork Reduction Act of 1995, we are required to provide 60-day notice in the **Federal Register** and solicit public comment before a collection of information requirement is submitted to the Office of Management and Budget (OMB) for review and approval. In order to fairly evaluate whether an information collection should be approved by OMB, section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 requires that we solicit comment on the following issues:

- The need for the information collection and its usefulness in carrying out the proper functions of our agency.
- The accuracy of our estimate of the information collection burden.
- The quality, utility, and clarity of the information to be collected.
- Recommendations to minimize the information collection burden on the affected public, including automated collection techniques.

We are soliciting public comment on each of these issues for the following sections of this document that contain information collection requirements (ICRs):

Proposed § 401.305 states that a provider or supplier must report and return an overpayment to the Secretary, the State, an intermediary, a carrier or a contractor to the correct address by the later of 60 days after the overpayment was identified or the date the corresponding cost report is due and notify the Secretary, the State, an intermediary, a carrier or a contractor in writing of the reason for the overpayment. The burden associated with this requirement would be the time and effort necessary to report and return the overpayment in the manner described at § 401.305.

For purposes of this section only, we estimate that approximately 125,000 providers and suppliers (or roughly 8.5 percent of the total number of Medicare providers and suppliers) would report and return overpayments in a typical year under our proposed provisions. In addition, we project that each of these providers and suppliers would, on average, separately report and return approximately 3 to 5 overpayments. We also estimate that it would take a provider or supplier approximately 2.5

hours to complete the applicable reporting form and return an overpayment. Lastly, the two main categories of individuals believed to complete and submit the applicable reporting form include: (1) Accountants and auditors (external and in-house); and (2) miscellaneous in-house administrative personnel. Each provider and supplier's individual operations is different and, as a result, it is not possible to break down the percentage of total affected providers of suppliers that would fall within the two aforementioned categories (for example, percentage of providers that would use an accountant). Consequently, in order to determine the burden cost, we utilize the average hourly wage of these two occupational categories based on the most recent wage data provided by the Bureau of Labor Statistics (BLS) data for May 2010. The mean hourly wage for the category of ''accountants and auditors'' is $33.15 (see *http://www.bls.gov/oes/current/oes132011.htm*) and the mean hourly wage for the category of ''bookkeeping, accounting, and auditing clerks'' is $16.99 (*http://www.bls.gov/oes/current/oes433031.htm*). The average of these two figures, including fringe benefits and overhead, is $37.10. This, in turn, leads to an aggregate annual ICR burden cost, attributable to the impacted 125,000 providers and suppliers for the range of 3 to 5 overpayments, of $34.78 million and $57.97 million, respectively. Again these are rough estimates, as the number of overpayments reported and returned will vary per provider and supplier. Therefore, we solicit comment on our burden assumptions and associated calculations.

TABLE 1—ANNUAL BURDEN REQUIREMENTS AND COSTS ASSOCIATED WITH REPORTING AND RETURNING OF OVERPAYMENTS (§ 401.305)

Number of impacted providers and suppliers	Number of overpayments processed per provider and supplier	Burden per overpayment reported and returned (hours)	Total annual burden (hours)	Hourly labor cost of reporting	Total cost (in millions)
125,000	3–5	2.5	937,500–1,562,500	$37.10	$34.78–$57.97

If you comment on these information collection and recordkeeping requirements, please do either of the following:

1. Submit your comments electronically as specified in the **ADDRESSES** section of this proposed rule; or

2. Submit your comments to the Office of Information and Regulatory Affairs, Office of Management and Budget, Attention: CMS Desk Officer, [CMS–6037–P], Fax: (202) 395–5806; or Email: *OIRA_submission@omb.eop.gov.*

IV. Response to Comments

Because of the large number of public comments we normally receive on **Federal Register** documents, we are not able to acknowledge or respond to them individually. We will consider all comments we receive by the date and time specified in the **DATES** section of this preamble, and, when we proceed with a subsequent document, we will respond to the comments in the preamble to that document.

V. Regulatory Impact Statement

A. Statement of Need

This proposed rule is necessary to implement section 6402(a) of the Affordable Care Act, which established a new section 1128J(d) of the Act entitled ''Reporting and Returning of Overpayments.'' Section 1128J(d)(1) of the Act requires a person who has received an overpayment to report and return the overpayment to the Secretary, the State, an intermediary, a carrier, or a contractor, as appropriate, at the correct address, and to notify the Secretary, State, intermediary, carrier or contractor to whom the overpayment was returned in writing of the reason for the overpayment. Section 1128J(d)(2) of the Act requires that an overpayment must be reported and returned by the later of—(1) the date which is 60 days after the date on which the overpayment was identified; or (2) the date any corresponding cost report is due, if applicable. Section 1128J(d)(3) of the Act specifies that any overpayment retained by a person after the deadline for reporting and returning an overpayment is an obligation (as defined in 31 U.S.C. 3729(b)(3)) for purposes of 31 U.S.C. 3729. As a result, this proposed rule clarifies to providers and suppliers their legal obligations regarding the reporting and returning of overpayments.

B. Overall Impact

We have examined the impact of this proposed rule as required by Executive Order 12866 on Regulatory Planning and Review (September 1993), Executive Order 13563 on Improving Regulation and Regulatory Review (January 18, 2011), the Regulatory Flexibility Act (RFA) (September 19, 1980, Pub. L. 96–354), section 1102(b) of the Act, section 202 of the Unfunded Mandates Reform Act (UMRA) of 1995 (Pub. L. 104–4), Executive Order 13132 on Federalism (August 4, 1999), and the Congressional Review Act (5 U.S.C. 804(2)).

Executive Orders 12866 and 13563 direct agencies to assess all costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects; distributive impacts and equity). Executive Order 13563 emphasizes the importance of quantifying both costs and benefits, of reducing costs, of harmonizing rules, and of promoting flexibility. A regulation impact analysis (RIA) must be prepared for major rules with economically significant effects ($100 million or more in any one year).

As discussed earlier in the preamble, even without a final regulation, all stakeholders are subject to the statutory requirements found in section 1128J(d) of the Act and could face potential False Claims Act liability, Civil Monetary Penalties Law liability, and exclusion from Federal health care programs for failure to report and return an overpayment. This proposed rule would impose a new deadline on the return of any overpayment that has been identified. We believe that this change would spur providers to be more diligent in reporting and returning overpayments. That will likely increase the overpayments that we collect, but we do not have a basis for estimating the magnitude of that change, and note the substantial uncertainty surrounding the magnitude of new collections. The burden costs for reporting and returning of overpayments, as discussed in section III. of this proposed rule, are estimated annually between $34.78 million to $57.97 million. As a result, this proposed rule is not an economically significant rule under Executive Order 12866. We solicit comment on the analysis and conclusions provided in the RIA.

The RFA requires agencies to analyze options for regulatory relief for small businesses, if a rule has a significant impact on a substantial number of small entities. For purposes of the RFA, small entities include small businesses, nonprofit organizations, and small governmental jurisdictions. Most hospitals and most other health care providers and suppliers are small entities, either by being nonprofit organizations or by meeting the Small Business Administration (SBA) definition of a small business and having revenues of less than $7 million to $34.5 million in any 1 year. (For details, see the Small Business Administration's Table of Size Standards at *http://www.sba.gov/sites/default/files/Size_Standards_Table.pdf*.) Individuals and States are not included in the definition of a small entity. We do not believe that the reporting and returning of overpayments identified by providers and suppliers of services will have a significant impact on a substantial number of small entities. The requirements of this rule add another program integrity tool, but do not replace existing overpayment recovery efforts. We are not preparing an analysis for the RFA because the Secretary has determined that this proposed rule will not have a significant impact on a substantial number of small entities.

Section 1102(b) of the Act requires us to prepare a regulatory impact analysis if a rule may have a significant impact on the operations of a substantial number of small rural hospitals. This analysis must conform to the provisions of section 603 of the RFA. For purposed of section 1102(b) of the Act, we define a small rural hospital as a hospital located outside of the Metropolitan Statistical Area and has fewer than 100 beds. The cost of the required reporting should be minimal for small rural hospitals because standard business practices dictate keeping accurate records concerning monies due and/or payable. We are not preparing an analysis for section 1102(b) of the Act because the Secretary has determined that this proposed rule will not have a significant impact on the operations of a substantial number of small rural hospitals.

Section 202 of the Unfunded Mandates Reform Act of 1995 requires that agencies assess anticipated costs and benefits before issuing any rule whose mandates require spending in any 1 year by State, local, or tribal governments, in the aggregate, or by the private sector, of $136 million. This proposed rule would have no effect on the annual expenditures of any State, local or tribal government, or the private sector.

Executive Order 13132 establishes certain requirements that an agency must meet when it promulgates a proposed rule (and subsequent final rule) that imposes substantial direct requirement cost on State and local governments, preempts State law, or otherwise has Federalism implications. Since this proposed rule does not impose any costs on State or local governments, the requirements of Executive Order 13132 are not applicable.

C. Alternatives Considered

In light of the statutory mandate in section 6402(a) of the Affordable Care Act, we did not consider any alternatives to the implementation of this provision. We did, however, contemplate several operational mechanisms to alleviate the burden on the provider and supplier communities.

First, we considered and elected to utilize the existing voluntary refund process. This would allow providers and suppliers to use a reporting mechanism with which they are already familiar.

Second, we contemplated the appropriate length of time in which overpayments must be reported and returned. A time period of less than 10 years was considered, as this would ease the burden on providers and suppliers. However, and as explained earlier, we selected 10 years because this is the outer limit of the False Claims Act statute of limitations. More importantly, we believe that the need to protect the Medicare Trust Fund was of primary importance. It is not possible for us to calculate the costs associated with a 10-year period versus, for instance, a 5-year period. We do, though, solicit comments on this issue, similar to our earlier solicitation of comments on the propriety of a 10-year period.

Third, as with the overpayment reporting period, we contemplated a reopening timeframe of less than 10 years. Yet we selected a 10-year timeframe in order to ensure that our reopening regulations are consistent with the 10-year lookback period. The costs of a shorter lookback period cannot be estimated, though we welcome comments on this issue.

We solicit comment on the analysis provided in this section.

D. Beneficiary Access

We do not anticipate any impact on beneficiary access to care as a result of this proposed rule. As mentioned, the only burden associated with our proposed provisions involves the ICR aspects of reporting and returning overpayments. We do not believe that this burden—which, in any event, would only affect a small percentage of providers and suppliers—would cause a particular provider or supplier to reduce the services it furnishes to beneficiaries.

List of Subjects

42 CFR Part 401

Claims, Freedom of information, Health facilities, Medicare, Privacy.

42 CFR Part 405

Administrative practice and procedure, Health facilities, Health professions, Kidney diseases, Medical devices, Medicare, Reporting and recordkeeping requirements, Rural areas, X-rays.

For the reasons set forth in the preamble, the Centers for Medicare & Medicaid Services proposes to amend Chapter IV as set forth below:

PART 401—GENERAL ADMINISTRATIVE REQUIREMENTS

1. The authority citation for part 401 continues to read as follows:

Authority: Secs. 1102 and 1871 of the Social Security Act (42 U.S.C. 1302 and 1395hh).

2. Part 401 is amended by adding subpart D to read as follows:

Subpart D—Reporting and Returning of Overpayments

Sec.
401.301 Basis and scope.
401.303 Definitions.
401.305 Requirements for reporting and returning of overpayments.

§ 401.301 Basis and scope.

This subpart sets forth the policies and procedures for reporting and returning overpayments to the Medicare program for providers and suppliers of services under Parts A and B of title XVIII of the Act as required by section 1128J of the Act.

§ 401.303 Definitions.

For purposes of this subpart—

Medicare contractor means a fiscal intermediary, carrier, durable medical equipment Medicare administrative contractor (DME MAC), or Part A/Part B Medicare administrative contractor.

Overpayment means any funds that a person has received or retained under title XVIII of the Act to which the person, after applicable reconciliation, is not entitled under such title.

Person means a provider (as defined in § 400.202) or a supplier (as defined in § 400.202).

§ 401.305 Requirements for reporting and returning of overpayments.

(a) *General.* (1) If a person has identified that it has received an overpayment the person must report and return the overpayment in the form and manner set forth in this section.

(2) A person has identified an overpayment if the person has actual knowledge of the existence of the overpayment or acts in reckless disregard or deliberate ignorance of the existence of the overpayment.

(b) *Deadline for reporting and returning overpayments.* (1) A person with an identified overpayment must report and return the overpayment by the later of either of the following:

(i) The date which is 60 days after the date on which the overpayment was identified.

(ii) The date any corresponding cost report is due, if applicable.

(2) The deadline for returning overpayments will be suspended when either of the following occurs:

(i) OIG acknowledges receipt of a submission to the OIG Self-Disclosure Protocol until such time as a settlement agreement is entered, the person withdraws from the OIG Self-Disclosure Protocol, or the person is removed from the OIG Self-Disclosure Protocol.

(ii) CMS acknowledges receipt of a submission to the Self-Referral Disclosure Protocol until such time as a settlement agreement is entered, the person withdraws from the Self-Referral Disclosure Protocol, or the person is removed from the Self-Referral Disclosure Protocol.

(c) *Applicable reconciliation.* (1) The applicable reconciliation occurs when a cost report is filed; and

(2) In instances when the provider—

(i) Receives more recent CMS information on the SSI ratio, the provider is not required to return any overpayment resulting from the updated information until the final reconciliation of the provider's cost report occurs; or

(ii) Knows that an outlier reconciliation will be performed, the provider is not required to estimate the change in reimbursement and return the estimated overpayment until the final reconciliation of that cost report.

(d) *Contents of report.* An overpayment required to be reported under this section to a Medicare contractor must be made in writing and must contain all of the following:

(1) Person's name.

(2) Person's tax identification number.

(3) How the error was discovered.

(4) The reason for the overpayment.

(5) The health insurance claim number, as appropriate.

(6) Date of service.

(7) Medicare claim control number, as appropriate.

(8) Medicare National Provider Identification (NPI) number.

(9) Description of the corrective action plan to ensure the error does not occur again.

(10) Whether the person has a corporate integrity agreement with the OIG or is under the OIG Self-Disclosure Protocol.

(11) The timeframe and the total amount of refund for the period during which the problem existed that caused the refund.

(12) If a statistical sample was used to determine the overpayment amount, a description of the statistically valid methodology used to determine the overpayment.

(13) A refund in the amount of the overpayment. A person may request an extended repayment schedule as that term is defined in § 401.603.

(e) *Reporting.* (1) A person must use the self-reported overpayment refund process set forth by the applicable Medicare contractor to report and return overpayments except as provided in paragraph (e)(2) of this section.

(2) A person satisfies the reporting obligations of this section by making a disclosure under the OIG's Self-Disclosure Protocol resulting in a settlement agreement using the process described in the OIG Self-Disclosure Protocol.

(f) *Enforcement.* Any overpayment retained by a person after the deadline for reporting and returning the overpayment specified in paragraph (b) of this section is an obligation for purposes of 31 U.S.C. 3729.

(g) *Lookback period.* An overpayment must be reported and returned in accordance with § 401.305 only if a person identifies the overpayment within 10 years of the date the overpayment was received.

Subpart F—Claims Collection and Compromise

§ 401.607 [Amended]

3. In § 401.607(c)(2)(i), the definition of ''Hardship'' is amended by removing the phrase ''outstanding overpayments (principal and interest)'' and adding in its place the phrase ''outstanding overpayments (principal and interest and including overpayments reported in accordance with §§ 401.301 through 401.305.)''

PART 405—FEDERAL HEALTH INSURANCE FOR THE AGED AND DISABLED

4. The authority for part 405 continues to read as follows:

Authority: Secs. 1102, 1862, and 1871 of the Social Security Act as amended (42 U.S.C.1302, 1395y, and 1395hh).

5. Section 405.980 is amended by adding paragraph (b)(6) to read as follows:

§ 405.980 Reopenings of initial determinations, redeterminations, and reconsiderations, hearings and reviews.

* * * * *

(b) * * *

(6) Within 10 years from the date of initial determination or redetermination if the overpayment is reported in accordance with § 401.305.

* * * * *

(Catalog of Federal Domestic Assistance Program No. 93.773, Medicare—Hospital Insurance; and Program No. 93.774, Medicare—Supplementary Medical Insurance Program)

Dated: August 18, 2011.

Donald M. Berwick,

Administrator, Centers for Medicare & Medicaid Services.

Approved: February 10, 2012.

Kathleen Sebelius,

Secretary, Department of Health and Human Services.

[FR Doc. 2012–3642 Filed 2–14–12; 8:45 am]

BILLING CODE 4120–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 76

[CS Docket No. 98–120; FCC 12–18]

Carriage of Digital Television Broadcast Signals: Amendment to the Commission's Rules

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: This Fourth FNPRM seeks comment on whether it would be in the public interest to extend the viewability rule and the HD carriage exemption, both of which are currently scheduled to sunset on June 12, 2012. First, we seek comment on whether to extend, in its current form, the ''viewability'' rule, which implements the statutory requirement that all cable subscribers, including those with analog equipment, be able to view must carry television signals. Second, given the apparent widespread reliance of small cable

operators on the HD exemption, we propose to extend it for an additional three years, but ask whether this should be the final extension. We note that both rule and exemption would have expired on February 17, 2012 if the DTV transition had not been delayed by Congress. The Commission is therefore concurrently issuing a Declaratory Order clarifying that both the viewability rule and the HD Carriage Exemption will sunset on June 12, 2012, absent Commission action to extend them.

DATES: Submit comments on or before March 12, 2012. Submit replies on or before March 22, 2012.

FOR FURTHER INFORMATION CONTACT: Lyle Elder, *Lyle.Elder@fcc.gov*, or Steven Broeckaert, *Steven.Broeckaert@fcc.gov* of the Media Bureau, Policy Division, at (202) 418–2120.

SUPPLEMENTARY INFORMATION: The proceeding this Fourth FNPRM initiates shall be treated as a ''permit-but-disclose'' proceeding in accordance with the Commission's *ex parte* rules.[1] Persons making *ex parte* presentations must file a copy of any written presentation or a memorandum summarizing any oral presentation within two business days after the presentation (unless a different deadline applicable to the Sunshine period applies). Persons making oral *ex parte* presentations are reminded that memoranda summarizing the presentation must (1) list all persons attending or otherwise participating in the meeting at which the *ex parte* presentation was made, and (2) summarize all data presented and arguments made during the presentation. If the presentation consisted in whole or in part of the presentation of data or arguments already reflected in the presenter's written comments, memoranda or other filings in the proceeding, the presenter may provide citations to such data or arguments in his or her prior comments, memoranda, or other filings (specifying the relevant page and/or paragraph numbers where such data or arguments can be found) in lieu of summarizing them in the memorandum. Documents shown or given to Commission staff during *ex parte* meetings are deemed to be written *ex parte* presentations and must be filed consistent with § 1.1206(b). In proceedings governed by § 1.49(f) or for which the Commission has made available a method of electronic filing, written *ex parte* presentations and memoranda summarizing oral *ex parte* presentations, and all attachments thereto, must be filed through the electronic comment filing system available for that proceeding, and must be filed in their native format (*e.g.,* .doc, .xml, .ppt, searchable .pdf). Participants in this proceeding should familiarize themselves with the Commission's *ex parte* rules. Pursuant to §§ 1.415 and 1.419 of the Commission's rules, 47 CFR 1.415, 1.419, interested parties may file comments and reply comments on or before the dates indicated on the first page of this document. Comments may be filed using the Commission's Electronic Comment Filing System (ECFS). *See Electronic Filing of Documents in Rulemaking Proceedings,* 63 FR 24121 (1998).

▪ *Electronic Filers:* Comments may be filed electronically using the Internet by accessing the ECFS: *http://fjallfoss.fcc.gov/ecfs2/*.

▪ *Paper Filers:* Parties who choose to file by paper must file an original and one copy of each filing. If more than one docket or rulemaking number appears in the caption of this proceeding, filers must submit two additional copies for each additional docket or rulemaking number.

Filings can be sent by hand or messenger delivery, by commercial overnight courier, or by first-class or overnight U.S. Postal Service mail. All filings must be addressed to the Commission's Secretary, Office of the Secretary, Federal Communications Commission.

▪ All hand-delivered or messenger-delivered paper filings for the Commission's Secretary must be delivered to FCC Headquarters at 445 12th St. SW., Room TW–A325, Washington, DC 20554. The filing hours are 8 a.m. to 7 p.m. All hand deliveries must be held together with rubber bands or fasteners. Any envelopes and boxes must be disposed of *before* entering the building.

▪ Commercial overnight mail (other than U.S. Postal Service Express Mail and Priority Mail) must be sent to 9300 East Hampton Drive, Capitol Heights, MD 20743.

▪ U.S. Postal Service first-class, Express, and Priority mail must be addressed to 445 12th Street SW., Washington, DC 20554.

People with Disabilities: To request materials in accessible formats for people with disabilities (braille, large print, electronic files, audio format), send an email to *fcc504@fcc.gov* or call the Consumer & Governmental Affairs Bureau at 202–418–0530 (voice), 202–418–0432 (tty).

Availability of Documents. Comments, reply comments, and *ex parte* submissions will be available for public inspection during regular business hours in the FCC Reference Center, Federal Communications Commission, 445 12th Street SW., CY–A257, Washington, DC 20554. These documents will also be available via ECFS. Documents will be available electronically in ASCII, Microsoft Word, and/or Adobe Acrobat.

Summary of the Final Rule

I. Introduction

1. In 2007, the Commission adopted certain rules to protect consumers as the transition to digital television (DTV) approached.[2] Specifically, in order to ensure that cable operators continued to comply with the statutory obligation to make must-carry television stations[3] ''viewable'' to all subscribers,[4] the Commission adopted a rule providing cable operators two options to comply with the viewability requirement: (1) Carry the digital signal in analog format to all analog cable subscribers, or (2) carry the signal only in digital format, provided that all subscribers have the necessary equipment to view the broadcast content.[5] In order to retain flexibility to deal with concerns arising after the DTV transition, the Commission stated that the viewability rule would sunset three years after the transition, subject to review during the last year of this period to determine if it should be extended, revised, or allowed to sunset.[6] This rule will therefore expire on June 12, 2012 unless we take action to extend it.

[1] 47 CFR 1.1200 *et seq.*

[2] *See generally Carriage of Digital Television Broadcast Signals,* CS Docket No 98–120, Third Report and Order and Third Further Notice of Proposed Rulemaking, 73 FR 6043, 22 FCC Rcd 21064 (2007) (''*Viewability Order''* or ''*Third FNPRM''*). As discussed below, the DTV transition was finalized on June 12, 2009.

[3] ''Must-carry'' stations are those stations subject to mandatory cable carriage (unless they elect to be carried only with their consent). These include both commercial (47 U.S.C. 534(a)) and non-commercial educational (47 U.S.C. 535(a)) full-power television stations.

[4] *See* 47 U.S.C. 534(b)(7) (''Signals carried in fulfillment of the requirements of this section [*i.e.,* commercial must-carry signals] shall be provided to every subscriber of a cable system. Such signals shall be viewable via cable on all television receivers of a subscriber which are connected to a cable system by a cable operator or for which a cable operator provides a connection''); 47 U.S.C. 535(h) (''Signals carried in fulfillment of the carriage obligations of a cable operator under this section [*i.e.,* non-commercial must-carry signals] shall be available to every subscriber'').

[5] 47 CFR 76.56(d)(3).

[6] 47 CFR 76.56(d)(5) (''The requirements set forth in paragraph (d)(3) of this section shall cease to be effective three years from the date on which all full-power television stations cease broadcasting analog signals, unless the Commission extends the requirements in a proceeding to be conducted during the year preceding such date.'').

2. Also in 2007, the Commission adopted a related rule regarding the prohibition on material degradation of broadcast signals when carried by cable systems. One aspect of this rule is the requirement that any signal broadcast in high definition (''HD'') also be carried by cable operators in HD. In response to concerns from commenters about cost and technical capacity, the Commission granted a three-year exemption from this HD carriage rule to the operators of certain small cable systems. As with the viewability rule, the Commission held that the small cable HD exemption would sunset in three years absent action by the Commission to revise or extend it. Thus, this exemption will also expire on June 12, 2012 unless the Commission takes action to extend it.

3. We initiate this Fourth Further Notice of Proposed Rulemaking (Fourth FNPRM) in the DTV cable carriage docket to determine whether it would be in the public interest to extend this rule and exemption. For the reasons described below, we seek comment on whether to extend the ''viewability'' rule for three more years to ensure that all cable subscribers, including those with analog equipment, continue to have access to must carry television signals. Given the apparent widespread reliance of small cable operators on the HD exemption, we propose to extend it for an additional three years, but ask whether this should be the final extension. We note that both rule and exemption would have expired on February 17, 2012 if the DTV transition had not been delayed by Congress. The Commission is therefore concurrently issuing a Declaratory Order clarifying that both the viewability rule and the HD Carriage Exemption will sunset on June 12, 2012, absent Commission action to extend them.[7]

II. Background

4. Pursuant to Section 614(b)(4)(B) of the Communications Act of 1934, as amended (the ''Act''),[8] the Commission initially opened this docket in 1998 to address the responsibilities of cable television operators with respect to carriage of digital broadcast stations in light of the nation's transition to digital television.[9] The 2007 *Viewability Order,* among other things, established a rule ensuring the viewability of must-carry signals on cable systems, as required by statute.[10] That order also established the requirement for cable systems to carry HD broadcast signals in HD, in order for the signals to be carried without material degradation.[11] Based on further comments, the follow-up *Fourth Report & Order* granted an exemption from this latter requirement for the operators of certain small cable systems.[12] As mentioned above, both the viewability rule and the HD carriage exemption were scheduled to sunset three years after the conclusion of the full-power transition, subject to review during the last year of this period to determine whether they should be extended, revised, or allowed to sunset.[13]

III. Viewability Rule

5. In the *Viewability Order,* the Commission found that ''viewability'' of must-carry digital signals was mandated by the Communications Act just as it had been for must-carry analog signals, and adopted a rule to ensure that these signals would be available to all cable subscribers.[14] The Commission recognized the need for flexibility in enforcing ''the most fundamental interest expressed in the must carry rules,''[15] and that it is bound by statute to ensure that must-carry signals are actually viewable by all subscribers. This review provides an opportunity for us to determine whether extending the current rule is necessary to fulfill that statutory mandate, given the current state of technology and the marketplace.

6. Since passage of the 1992 Cable Act, the Commission has consistently found that ''mere transmission of the must-carry signal is not sufficient to meet the requirements'' of the statute.[16] As explained in 1993:

> We believe that the 1992 Act is clear in its requirement that all local commercial television stations carried in fulfillment of the must-carry requirements must be provided to every cable subscriber and must be viewable on all television sets that are connected to the cable system by a cable operator for which the cable operator provides a connection. The Act does not give the Commission authority to exempt any class of subscribers from this requirement.[17]

Therefore, must-carry stations must be viewable.[18] After the DTV transition, ''the signals of must-carry stations [would have been] completely unavailable to analog cable subscribers'' absent Commission action.[19] That is, because after the transition these signals are broadcast only in digital, cable subscribers that do not own a digital television or subscribe to a digital tier (and therefore lease or own a digital navigation device) would no longer be able to view these stations through their cable operator. Although the digital signals of these must-carry stations could theoretically be accessed over-the-air with the use of a digital converter box, the statute does not require subscribers to take that approach.[20] Moreover, even were the law to contemplate that approach, we note that, as a technical matter, not all analog cable subscribers are covered by the signals from their local must-carry stations or even own an antenna that would permit them to receive the signal if it were available. As stated in 2007, we remain ''bound by statute to ensure that commercial and non-commercial mandatory carriage stations are actually viewable by all cable subscribers,''[21] and ''[t]hese statutory requirements plainly apply to cable carriage of digital broadcast signals.''[22]

[7] As discussed in detail in Section V, *infra.*

[8] 47 U.S.C. 534(b)(4)(B).

[9] Carriage of the Transmissions of Digital Television Broadcast Stations: Amendment to Part 76 of the Commission's Rules, CS Docket No. 98–120, Notice of Proposed Rulemaking, 13 FCC Rcd 15092, 15093, paras. 1–2 (1998).

[10] See generally Viewability Order.

[11] Viewability Order at para. 4.

[12] *See generally, Carriage of Digital Television Broadcast Signals,* CS Docket No. 98–120, Fourth Report and Order, 23 FCC Rcd 13618 (2008) (''*Fourth Report & Order''*).

[13] Viewability Order at para. 16; Fourth Report & Order at para. 12.

[14] Viewability Order at para. 15.

[15] Viewability Order at para. 34.

[16] *Carriage of Digital Television Broadcast Signals,* CS Docket No. 98–120, Second Further Notice of Proposed Rulemaking, 22 FCC Rcd 8803 (2007) (''*Second FNPRM''*).

[17] Implementation of the Cable Television Consumer Protection and Competition Act of 1992, etc., MM Docket No. 92–259, Report and Order, 8 FCC Rcd. 2965, 2974 (1993) (''*Analog Must Carry Report and Order''*).

[18] We note that although Sections 614(b)(7) (commercial) and 615(h) (noncommercial) of the Act use different language, the Commission consistently has treated them as imposing identical obligations with regard to viewability. *See e.g., Analog Must Carry Report and Order,* 8 FCC Rcd. at 2974, at para. 32 (noting that all must-carry signals must be available to all subscribers); *see also Implementation of Section 302 of the Telecommunications Act of 1996: Open Video Systems,* CS Docket No. 96–46, Second Report and Order, 11 FCC Rcd 18223, 18308, at para. 162 (1996) (''Pursuant to Section 614(b)(7) and 615(h), the operator of a cable system is required to ensure that signals carried in fulfillment of the must-carry requirements are provided to every subscriber of the system.'').

[19] Viewability Order at para. 55.

[20] The Commission has long held, and the Supreme Court has agreed, that cable subscribers' use of an ''A/B switch'' to access over-the-air signals is not a legitimate replacement for access to those signals on the cable system itself. *Turner Broadcasting System, Inc.* v. *FCC,* 520 U.S. 180 at 219–221 (1997) (''*Turner Two''*). An ''A/B switch'' is a method of manually toggling between cable and broadcast programming without changing the viewing device.

[21] Viewability Order at para. 31.

[22] *Viewability Order* at para. 15; *see also e.g.,* para. 22 (the digital viewability requirement is ''based on a straightforward reading of the relevant statutory text''); para. 24 (''this language reflects Congress's unambiguous determination that broadcast signals must be viewable by all cable subscribers''); para. 34 (''[i]f we declined to enforce the viewability requirement it would render the

Continued

7. As the Commission also made clear in 2007, viewability of broadcast signals is not only mandated by statute, but is also of vital importance to the broadcast stations that rely on the Commission's "must carry" rules and to all consumers of television programming. The Commission noted that,

[i]f cable operators did not downconvert the digital signals, broadcasters would stand to lose an audience of millions of households that are analog cable subscribers and the concomitant advertising revenues, thus jeopardizing their continued health and viability. Should these stations deteriorate or cease to exist, the impact of these lost programming options would fall most heavily on those that most need them: The roughly fifteen percent of Americans who rely solely on over-the-air television, which disproportionately consist of low-income and minority households.[23]

Furthermore, the Commission found that, without action, "analog cable subscribers and households that rely solely on over-the-air broadcast television may well face 'a reduction in the number of media voices' and the loss of 'the widest possible dissemination of information from diverse and antagonistic sources.'" [24] The Commission, in the *Viewability Order,* explained that at the time half of all consumers relied on the analog tuners in the equipment that they owned, and that the welfare of those consumers "drives the Commission's decisions on viewability." [25] Thus, in adopting the *Viewability Order,* the Commission acted in light of both the statutory directive and the important governmental interests of preserving the benefits of free, over-the-air local broadcast television for analog cable subscribers and over-the-air viewers alike, and promoting the widespread dissemination of information from a multiplicity of sources.

8. In order to ensure that digital signals would be actually viewable by all subscribers, the Commission adopted a two-part rule and allowed systems to choose how they would comply. Section 76.56(d)(3) of the Commission's rules provides:

(3) The viewability and availability requirements of this section require that, after the broadcast television transition from analog to digital service for full power television stations cable operators must either:

(i) Carry the signals of commercial and non-commercial must-carry stations in analog format to all analog cable subscribers, or

(ii) For all-digital systems, carry those signals in digital format, provided that all subscribers, including those with analog television sets, that are connected to a cable system by a cable operator or for which the cable operator provides a connection have the necessary equipment to view the broadcast content.[26]

This rule ensures that all subscribers are able to view must-carry programming, while still providing flexibility to operators who have been, and continue to be, transitioning to an all-digital system on their own schedules.[27] Once a particular cable operator has begun transmitting its content exclusively in a digital format, all subscribers will have access to digital broadcast signals via the digital equipment necessary to view all of the other programming offered by the cable operator. Thus, under the current rule, an all-digital cable operator can comply by transmitting all of its content in a digital format to all of its subscribers.

9. We seek comment on whether we should extend the viewability rule or permit it to sunset.[28] The proceeding we begin today provides an opportunity for us to consider whether extending this rule best fulfills the statutory mandate, by reviewing it "in light of the potential cost and service disruption to consumers, and the state of technology and the marketplace." [29] As discussed below, the available market evidence seems to indicate that the viewability requirements remain important to consumers.[30] In 2007 there were approximately 40 million analog-only cable subscribers,[31] and there are still millions today. According to data provided by NCTA, the rate at which customers switch to digital has slowed since the DTV transition,[32] and as of the third quarter of 2011, more than twelve million cable households were reliant on analog cable delivery.[33] Moreover, the vast majority of cable subscribers are served by "hybrid" systems that provide both analog and digital service, even if they receive digital service to one or more television sets.[34] A number of these digital subscribers still rely on analog cable for second televisions in the home, meaning that there are potentially millions more subscribers who rely on analog to some extent.[35] We seek comment on whether the figures discussed above reflect the current market for cable service and how that should impact the Commission's decision on whether to allow the viewability rule to sunset.

10. The sunset of the viewability rule would potentially impact millions of subscribers, and the broadcasters who would be unable to reach them.[36] There are hundreds of broadcast stations that rely on the must carry rules to ensure carriage on cable systems—in 2010, almost 40 percent of all broadcast stations elected or defaulted to must carry rather than electing retransmission

regime almost meaningless, contrary to the clearly expressed will of the Congress as upheld by the Supreme Court").

[23] *Id.* at para. 55 (internal citations omitted).

[24] *Id.*

[25] *Id.* at n. 131.

[26] 47 CFR 76.56(d)(3).

[27] Under this rule, in combination with the material degradation rule, discussed *infra,* a "hybrid" system (providing both analog and digital service) would also have to carry an HD broadcast signal in HD. As the Commission has previously explained, "there should be no perceivable difference between" SD digital and analog picture quality, so "our rules do not require cable operators * * * to carry an SD digital version of a broadcast station's signal, in addition to the analog version" as long as all subscribers can view the channel. *See supra* n. 12, *Fourth Report & Order* at para. 5.

[28] If we decide to extend the term of the viewability rule, we propose that the Commission should conduct a further review of this rule prior to June 12, 2015, and if the Commission does not act to extend it by that date, the viewability rule will sunset.

[29] *Viewability Order* at para. 16.

[30] The data upon which we rely includes data gathered by the Commission via the Annual Cable Operator Report and the annual Cable Price Survey, and commercially produced data such as that provided by SNL Kagan. *See e.g., infra* notes 31–34.

[31] Viewability Order at note 3.

[32] NCTA Industry Data, *http://www.ncta.com/Statistics.aspx, http://www.ncta.com/Stats/CableAvailableHomes.aspx, http://www.ncta.com/Stats/BasicCableSubscribers.aspx,* visited 2/9/12.

[33] As of the third quarter of 2011, Kagan indicates that there are more than 58 million cable subscribers, of whom approximately 46 million are digital cable subscribers. *Q3 video subscriber trends improve but still lack real strength,* Broadband Technology (SNL Kagan, Charlottesville, VA), November 25, 2011, at 2. The vast majority of these digital cable subscribers are served by hybrid, rather than all-digital, systems. Staff analysis of 2010 Annual Cable Operator Report (Form 325) (indicating fewer than eight million cable subscribers were served by all-digital systems).

[34] Staff analysis of 2010 Annual Cable Operator Report (Form 325) (indicating fewer than eight million cable subscribers were served by all-digital systems). The *Viewability Order* stated that "[t]o assist the Commission in this review, we will include questions in our annual Cable Price Survey to assess, for example, digital cable penetration, cable deployment of digital set-top boxes with various levels of processing capabilities, and cable system capacity constraints." *Id.* at n. 39. Based on data submitted to the Commission as part of the 2010 Cable Price Survey, only 9.4% of subscribers are served by all-digital systems.

[35] A recent survey indicates that 31 percent of homes do not have a digital television. *See CES: Over Two Thirds of U.S. Homes Have HDTVs,* Broadcasting & Cable tvfax, Jan. 5, 2012, at 4–5 (discussing the results of a survey conducted by the Leichtman Research Group, Inc.).

[36] *See In the Matter of TiVo, Inc,* 26 FCC Rcd 12743, 12747 (2011) ("NCTA notes, however, that although the cable industry has significantly increased the penetration of its digital services since the Commission adopted the *Digital Plug and Play Order* in 2003, many cable systems 'continue to carry substantial numbers of channels only in analog,' and 'even on systems that simulcast all channels in digital, some customers may subscribe only to analog service.'") (NCTA Comments at 2–3).

consent.[37] Without the viewability rule, many cable subscribers would be required to pay more for access to must-carry broadcast stations, by replacing existing and still-functional analog equipment with digital equipment or leasing set top boxes to view the complete service they currently pay for and receive in analog.[38] As the Supreme Court has made clear, ''preserving the benefits of free, over the air local broadcast television'' is an ''important governmental interest'' at the very heart of the must-carry regime.[39] In this regard, we seek comment on how the sunset of the viewability requirement would impact the financial resources of must carry stations. We seek specific information that will allow us to build a solid record that supports either the retention or the sunset of the viewability rule. Also, given that ''viewability'' of must-carry digital signals is mandated by the Communications Act, we seek comment on whether it is necessary to extend the rule in its current form as opposed to relying on stations to file carriage complaints to enforce compliance with the statutory mandate.[40]

11. As discussed in the *Viewability Order,* compliance with this rule may result in some costs to cable operators.[41] In some cases operators may be required to carry more than one version of a channel, using more bandwidth than they would if they carried only a single version, and in some cases they may be required to down-convert a broadcast signal to make the additional version available to analog subscribers. At the time of the *Viewability Order,* however, these costs were not only determined to be necessary to carry out the statutory ''viewability'' directive, but were determined to be outweighed by the benefits of the viewability rule. Although many broadcast stations elect must-carry status, a cable system carries many more non-broadcast channels. The Commission explained that the comparatively small number of must-carry stations carried by any given system meant that the incremental additional bandwidth consumed by compliance with this requirement would be ''negligible'' [42] even for hybrid systems, which are required by this rule to devote at least one 6 MHz channel to each must-carry station.[43] We seek comment on the extent to which these conclusions still hold true today.

[37] Staff analysis of 2010 Annual Cable Operator Report (Form 325) (indicating approximately 780 of approximately 2000 stations elected or defaulted to must carry). Based on data submitted to the Commission as part of the 2010 Cable Price Survey, over 96% of cable systems carry at least one must-carry station, and, on average, each system carries more than seven must-carry stations.

[38] Subscribers to Direct Broadcast Satellite systems must have boxes for all televisions in the home; this requirement was not changed as a result of the DTV transition. Similarly, subscribers to all-digital cable systems must either have a box for each set, or own equipment capable of displaying digital signals without a box. In this case, subscribers face no additional expense or effort to receive must-carry signals in digital.

[39] Turner Two, supra n. 21.

[40] Carriage complaints may only be filed by the affected station, not by viewers or other parties. 47 CFR 76.61.

[41] *Viewability Order,* at paras. 26–35.

12. Furthermore, the Commission affirmed in the *Viewability Order* that the ''one-third carriage cap,'' under which cable operators need dedicate no more than one-third of their channel capacity to commercial broadcast stations, remains in effect in the digital carriage context, and that all versions of a signal would count toward this cap.[44] As a result, no cable system need ever dedicate more than one-third of their bandwidth to carriage of commercial broadcast stations, and may choose which signals not to carry if they ever reach this cap. We seek comment on whether the situation has changed regarding bandwidth usage, and whether any cable system has reached the one-third carriage cap. Regarding the cost of downconversion, some commenters in the 2007 viewability proceeding claimed they would face large costs to down-convert broadcast signals.[45] The Commission was skeptical of at least some of these claims, all of which concerned up-front expenses. Given the up-front nature of the claimed expenses, they presumably would have already been incurred by now and would not impose an additional cost. We seek comment on the accuracy of this presumption in the current marketplace. Would retention of the viewability rule impose any additional expenses on cable operators? If so, we request a detailed description of any claimed expenditures and associated cost information.

13. We note that some cable operators, such as RCN and BendBroadband, transmit only digital signals and have eliminated analog service in all of their systems.[46] As discussed above, these providers can comply fully with their viewability obligations by simply carrying a must-carry signal in digital, often in the same manner as it is provided by the broadcast station. We therefore also seek comment about costs associated with transitioning to an all-digital system, rather than carrying analog versions of must-carry signals. According to information in the 2007 record, virtually all cable operators are planning to eventually transition to all-digital systems, regardless of our decision on the viewability rule.[47] How many hybrid systems plan to go all-digital in the near future, and how many subscribers will be impacted by this shift? What is the range of costs per digital box for cable operators, and the range of rental fees charged to subscribers who are first-time digital subscribers? How has the rate at which consumers voluntarily drop analog service changed in the time since the DTV transition? What is the current rate at which they are doing so? We seek comment on the business environment in which hybrid systems operate. Are competitive pressures on these systems such that they are transitioning to all-digital service at a faster rate than customers are switching on their own? Are any cable operators considering transitioning to an all-digital system more quickly than originally planned specifically because of the viewability obligations? What additional costs would be associated with an early transition? Commenters stating that they intend to or know of cable systems that intend to transition early due to the viewability rule should provide a detailed description of the claimed expenditures and cost information that they would face as the result of this early transition.

[42] *Viewability Order,* at para. 26.

[43] The bandwidth that must be allotted (due to the related prohibition on material degradation, discussed *infra*) increases only slightly if the must-carry station is broadcasting in high definition, due to the efficiencies of digital carriage.

[44] *Viewability Order,* at para. 36.

[45] *Viewability Order,* at para. 35.

[46] Basic Service Tier Encryption; Compatibility Between Cable Systems and Consumer Electronics Equipment, FCC 11–153, Notice of Proposed Rulemaking, 26 FCC Rcd 14870, 14876, para.8 (2011).

14. We seek comment on whether to extend the existing viewability rule. To the extent the Commission decides to retain the rule, we seek comment on whether it should be retained for another three years or a different period of time. Is three years too long or is a sunset at some later date more advisable? The Commission considered possible alternative rules in the *Viewability Order,* but each was rejected. The alternatives were rejected in each case because the Commission did ''not believe we have the authority to exempt any class of subscribers from this requirement,'' [48] and each of these alternative approaches would result in some subscribers losing access to must-carry signals.[49]

[47] *Viewability Order,* at para. 20.

[48] *Viewability Order*, at para. 39.

[49] For instance, Entravision, licensee of a number of commercial broadcast stations, proposed

Continued

15. Unlike the alternatives proposed, the rule the Commission adopted in 2007 ensures viewability by all subscribers, while simultaneously giving cable operators the flexibility to choose the best option for complying with their viewability obligations.[50] We seek comment on whether this rule is still necessary to ensure subscriber access to must-carry signals and support the continued viability of must-carry stations. What are the costs and benefits, for subscribers, broadcasters, and cable operators, of retaining this rule for another three years? To the extent feasible, commenters should quantify in dollars any asserted costs or benefits. We have not received any complaints under this rule, nor have we received any requests to waive it, from cable systems large or small. This speaks well of the compliance efforts of operators. It also seems to indicate that the burden of compliance has been relatively minimal and that the actual costs of compliance have likely not been onerous. We seek comment on whether this observation is accurate. How many subscribers, particularly those with some digital service, still rely in part on analog cable service? We seek comment generally on the cost and service disruption to consumers if the current rule was allowed to sunset. In particular, we seek comment on the number of cable subscribers whose residences lie outside the digital noise limited service contour of their local broadcast must-carry stations and therefore would have difficulty receiving a quality broadcast signal over the air.[51] Further, we seek comment on the number of cable subscribers that own antennas capable of receiving their local broadcast must-carry stations where such signals are available.

16. Finally, we seek comment on any other proposals that would achieve the results necessary to assure the viewability of must-carry signals through an approach different than that of our existing rule. To the extent any parties find the current rule burdensome, we seek comment on proposals that will satisfy the statute in a less burdensome manner. Is any rule necessary to effectuate the statutory intent? If so, any proposals for an alternative rule to ensure the actual viewability of must-carry signals should include specific proposed wording, as well as an analysis of how the proposal is consistent with the statute.[52] In the *Viewability Order,* we previously determined that the viewability rule was consistent with constitutional requirements.[53] We seek comment on any marketplace or other changes that have since occurred that may impact our analysis of the constitutional issues. To the extent that we allow the rule to sunset, we seek comment on how, as a legal and technical matter, the Commission would ensure cable operators' compliance with the statutory requirement to make all must-carry broadcast signals actually viewable to all subscribers.[54]

IV. HD Carriage Exemption

17. The Act also requires that cable operators carry broadcast signals ''without material degradation.'' [55] As the Commission has interpreted the Act in the context of carriage of digital signals, this requirement has two parts: Cable operators may not discriminate in their carriage between broadcast and non-broadcast signals, and HD broadcast signals must be carried to viewers in HD.[56] In the *Third FNPRM,* the Commission sought comment on alternatives to these rules [57] that would ''minimize the economic impact for small cable operators while still complying with the statutory requirements.'' [58]

18. Based on the comments received in response to the *Third FNPRM,* and in consideration of the effect of this requirement on operators of small cable systems, the *Fourth Report & Order* adopted a temporary exemption from the HD carriage requirement for certain small systems.[59] Commenters in that proceeding argued that, without an exemption from the material degradation rules, ''small systems [would] be forced to absorb or impose significant and unsustainable price increases, or in some instances to shut down altogether.'' [60] This is because some small systems did not have the technical capability or system capacity to carry high definition digital signals, and in some cases had so few subscribers that per-subscriber costs to upgrade to that capacity would be so high as to make it not worthwhile to continue operating the system.[61] The exemption adopted by the Commission applies to operators of cable systems with 2,500 or fewer subscribers that are not affiliated with a cable operator serving more than 10 percent of all MVPD subscribers, and to those with an activated channel capacity of 552 MHz or less. It permits such systems to carry broadcast signals in standard definition (SD) digital or analog, even if the signals are provided in HD.[62]

19. The exemption was not intended to be permanent, however. The Commission instead provided it for a three-year window, in order to give small systems ''a clear opportunity to come into compliance with the rules by spreading their effort and costs over an extended period.'' [63] Recognizing the connection to the viewability rule,

requiring all must-carry stations to be provided in analog to all of a cable system's subscribers until 85 percent of the served population had the means to view a digital signal. At that point, the operator could drop the analog version of all must-carry signals. *Viewability Order* at para. 39. The Commission rejected this proposal because it concluded that its statutory authority precluded the exemption of any class of subscribers from the viewability rule no matter how small that class might be. *Id.* Comcast and other cable operators proposed a rule that would allow them to carry must-carry signals in digital so long as they made equipment available for lease or sale to subscribers that would allow the subscribers to view the digital signal. *Id.* at para. 22. The Commission rejected this proposal because it would essentially require current analog subscribers to pay extra for the digital tier to watch must-carry signals they have a statutory right to receive on every tier of service, noting that ''[f]or every receiver 'connected to a cable system by a cable operator or for which a cable operator provides a connection,' that operator must ensure that the broadcast signals in question are actually viewable on their subscribers' receivers.'' *Id.,* citing 47 U.S.C. 534(b)(7). The National Association of Broadcasters proposed a rule that would require all broadcast signals to be carried in the same manner by a cable system—that is, ''if one must carry station is carried in analog, all broadcasters, whether carried pursuant to retransmission consent or must carry, would be carried in analog.'' *Id.* at para. 21. A system could therefore decline to provide any broadcast signals in analog without violating this comparative rule, even if that disenfranchised all of its analog subscribers. In each of the proposals outlined above, there is the potential, if not a certainty, that must-carry signals would not be viewable by analog subscribers.

[50] *Viewability Order* at para. 38.

[51] *See e.g.,* 47 CFR 73.622(e).

[52] To the extent we retain the rule for a specified period, we believe that it is appropriate to again consider the state of the marketplace before allowing the rule to sunset.

[53] *Viewability Order,* 22 FCC Rcd at 21083–21099.

[54] 47 U.S.C. 534(b)(7); 47 U.S.C. 535(h).

[55] *See* 47 U.S.C. 534(b)(4)(A) (''The signals of local commercial television stations that a cable operator carries shall be carried without material degradation. The Commission shall adopt carriage standards to ensure that, to the extent technically feasible, the quality of signal processing and carriage provided by a cable system for the carriage of local commercial television stations will be no less than that provided by the system for carriage of any other type of signal.'') and 535(g)(2) (''A cable operator shall provide each qualified local noncommercial educational television station whose signal is carried in accordance with this section with bandwidth and technical capacity equivalent to that provided to commercial television broadcast stations carried on the cable system and shall carry the signal of each qualified local noncommercial educational television station without material degradation.'').

[56] *Viewability Order,* at para. 4.

[57] *See* 47 CFR 76.62.

[58] *Third FNPRM* at para. 80, citing the *Second FNPRM* at para. 12.

[59] See generally Fourth Report & Order.

[60] National Cable & Telecommunications Association Comments at 12 (March 3, 2008).

[61] Fourth Report & Order at paras. 6–7.

[62] Fourth Report & Order at para. 18.

[63] Fourth Report & Order at para. 11.

which was adopted at the same time as the HD carriage requirement and also has an impact on cable carriage of broadcast signals, the Commission determined that this exemption should be reviewed in conjunction with that rule.[64]

20. We tentatively conclude that it is in the public interest to extend the small-system HD exemption for another three years because the number of systems relying on the exemption indicates that three years did not provide sufficient time for some small systems to come into compliance in a cost-effective way.[65] As discussed above, the Commission originally declined to make this exemption permanent in order to retain flexibility, and in order to have an opportunity to review the state of the marketplace several years after the digital broadcast transition.[66] Although the Commission anticipated that the three year exemption would give small systems an opportunity to come into compliance by making relatively large expenditures over a longer period of time, based on the most recent available data from the Annual Cable Operator Report, 37 percent of small systems that reported data, and that would be eligible for the exemption, were still not providing any HD service.[67] To the extent that most markets have at least one station broadcasting in HD, a system is almost certainly relying on the exemption if it is not carrying any signals in HD.[68] Thus, the Form 325 data indicate that a large number of small systems are relying on the exemption.[69] Form 325 does not provide information about why these small systems are not providing HD service, but at the time the exemption was adopted the Commission anticipated that the most likely reason would be the savings from not upgrading the cable plant to provide digital signals. We seek comment on this analysis. How many small cable operators are currently relying on this exemption? We seek comment on why they are doing so, rather than offering HD programming to their subscribers. We seek comment on the business environment in which these systems operate; are competitive pressures from direct broadcast satellite providers and over builders on these systems such that they would be carrying broadcast signals in HD if it were cost effective? As we stated we would in the *Fourth Report & Order,* we seek comment on the ''cost and service disruption to consumers'' who subscribe to these cable systems and do not receive any high definition programming, and on any disruptions that would occur if we retain the exemption. Have any broadcasters or cable operators received viewer complaints concerning the lack of HD programming from subscribers to such systems?

21. As noted above, the central purpose of the exemption was to provide small systems with additional time to upgrade and, where necessary, expand their systems to come into full compliance with the material degradation provisions of the carriage rules by carrying HD versions of all HD broadcast signals without making relatively large expenditures over a short period of time.[70] Have systems taken, or are systems taking, the opportunity to do so? As discussed above, commenters cited in the *Fourth Report & Order* argued that the costs of providing digital service were simply too high for some systems to bear.[71] Will any of these systems still lack sufficient opportunity to upgrade if the exemption is extended for three years? Given that not all eligible systems are taking advantage of the exemption,[72] and no non-eligible system has sought an exemption from this requirement, should the definition of ''small system'' for the purposes of this exemption be narrowed? Are there any systems providing some HD service but not carrying all broadcast signals in high definition? Should we consider revising the exemption such that stations would be required to carry all local broadcast signals in HD if they provide any HD service? We particularly seek data regarding any systems that have taken advantage of the exemption, but either already have begun or have firm plans to begin providing HD broadcast signals in HD. We also seek comment more generally on the costs and benefits of the exemption, for subscribers, broadcasters, and small cable operators. For example, has the exemption benefited small cable system operators by allowing them to direct capital expenditures to upgrade or introduce new services? Conversely, has the exemption unnecessarily allowed small cable operators simply to delay compliance with their material degradation obligations, thereby denying subscribers access to HD broadcast signals? To the extent feasible, commenters should quantify in dollars any asserted costs or benefits.

22. Comments at the time of the initial grant of this exemption indicated that it was necessary to protect the economic health of some small systems, and indeed that some systems might become too expensive to continue operation without the exemption.[73] We seek comment on whether and to what extent this remains the situation today. We seek comment more generally on ''the state of technology and the marketplace'' as they relate to this exemption. Finally, we seek comment on whether the benefits to the operators of small cable systems of extending this exemption for three years would outweigh the costs to subscribers and broadcasters. In proposing to extend the HD carriage exemption, we are guided by the Commission's determination in the *Fourth Report and Order* that ''[a] three-year sunset provides the Commission with the opportunity after the transition to review these rules in light of the potential cost and service disruptions to consumers, and the state of technology and the marketplace.'' [74] We are unaware of any marketplace changes that would make extension of the exemption for three additional years inadvisable. However, we assume the need for this exemption will not be permanent; if we extend the exemption, should we clarify that the Commission will not consider another extension? If the proposal to extend for three more years is adopted, small systems will have had a total of six additional years to come into compliance with the HD carriage requirement. We seek comment on whether three years is an appropriate amount of time, or if the HD carriage exemption should be retained for a different period of time.

V. Declaratory Order

23. Subsequent to the Commission's adoption of the *Viewability Order* and the *Fourth Report and Order,* the full-power transition was successfully completed on June 12, 2009, after Congress chose to delay it from the originally scheduled conclusion on February 17, 2009.[75] When adopting the *Viewability Order,* the Commission

[64] *Id.* at para. 12.

[65] We propose to have the Commission conduct a further review of this exemption during the last year of the three year period (between June 12, 2014 and June 12, 2015), and if the Commission does not decide to extend it, the exemption will sunset.

[66] Fourth Report & Order at para. 11.

[67] Staff analysis of 2010 Annual Cable Operator Report (Form 325).

[68] Approximately 99% of non-eligible cable systems are carrying at least one HD signal. Staff analysis of 2010 Annual Cable Operator Report (Form 325).

[69] *See infra* Appendix B (discussing our analysis of FCC Form 325 data).

[70] Fourth Report & Order at para. 11.

[71] *See supra* para. 16.

[72] *See infra* Appendix B.

[73] Fourth Report & Order at para. 7.

[74] Fourth Report & Order, at para. 11.

[75] *Full-Power TV Broadcasters Go All-Digital,* Federal Communications Commission, Press Release (June 13, 2009).

stated that, barring later action, the sunset of the viewability rule would occur ''three years from the date on which all full-power television stations cease broadcasting analog signals,'' which will be June 12, 2012.[76] The HD carriage exemption was intended to be ''in force for three years from the date of the digital transition'' and reviewed ''simultaneously with the viewability rule[ ].''[77] The Commission stated that the exemption would therefore be in force ''from February 18, 2009 through February 17, 2012,'' or three years after the originally scheduled conclusion of the transition.[78] The Commission expressed a clear intent to have the HD carriage exemption and viewability sunsets running in parallel, and did not at the time anticipate the subsequent congressionally mandated extension of analog broadcasting. It is clear from the text of the *Viewability Order* and the *Fourth Report and Order* that the Commission intended the rule/exemption to remain in effect 3 full years from the conclusion of the transition, and thus having them sunset four months early in February 2012 would be contrary to the stated intent of the Commission.[79] Therefore, we hereby issue this Declaratory Order that the HD carriage exemption, like the viewability rule, will be in effect up to and until June 12, 2012, absent further Commission action.

VI. Procedural Matters

A. Initial Paperwork Reduction Act of 1995 Analysis

24. The *Fourth FNPRM* has been analyzed with respect to the Paperwork Reduction Act of 1995 (''PRA'').[80] This document does not contain new or modified information collection requirements subject to the PRA, Public Law 104–13. In addition, therefore, it does not contain any new or modified ''information collection burden for small business concerns with fewer than 25 employees,'' pursuant to the Small Business Paperwork Relief Act of 2002, Public Law 107–198, *see* 44 U.S.C. 3506(c)(4).

B. Initial Regulatory Flexibility Analysis

25. As required by the Regulatory Flexibility Act of 1980, as amended (''RFA'')[81] the Commission has prepared this Initial Regulatory Flexibility Analysis (''IRFA'') of the possible economic impact on a substantial number of small entities by the policies and rules proposed in this *Fourth Notice of Proposed Rulemaking* (''*Fourth FNPRM''*). Written public comments are requested on this IRFA. Comments must be identified as responses to the IRFA and must be filed by the deadlines for comments on the *Fourth FNPRM* as indicated on its first page. The Commission will send a copy of the *Fourth FNPRM,* including this IRFA, to the Chief Counsel for Advocacy of the Small Business Administration (''SBA'').[82] In addition, the *Fourth FNPRM* and IRFA (or summaries thereof) will be published in the **Federal Register**.[83]

1. Need for, and Objectives of, the Proposals

26. This *Fourth FNPRM* seeks comment on rules relating to the manner in which broadcast DTV content will be displayed when it is carried by a cable system. The current viewability rule and the exemption from the HD carriage rule for certain small systems were both intended to expire three years after the conclusion of the transition, subject to a simultaneous review during the prior year. This *Fourth FNPRM* seeks comment on whether to extend for three years the current viewability rule, which requires that cable operators must either carry the signals of commercial and non-commercial must-carry stations in analog format to all analog cable subscribers, or, for all-digital systems, carry those signals in digital format, provided that all subscribers, including those with analog television sets, that are connected to a cable system by a cable operator or for which the cable operator provides a connection have the necessary equipment to view the broadcast content. Viewability of must-carry signals is required by the Communications Act, and as a result the current rule must be extended or replaced by an alternative that provides the same level of subscriber access to must-carry programming. The *Fourth FNPRM* also proposes to extend for three years the HD carriage exemption, which exempts certain small systems from the obligation to carry HD broadcast signals in HD. The exemption applies to operators of cable systems with 2,500 or fewer subscribers that are not affiliated with a cable operator serving more than 10% of all MVPD subscribers, and to those with an activated capacity of 552 MHz or less. The *Fourth FNPRM* seeks comment on the exemption's impact and importance.

2. Legal Basis

27. The authority for the action proposed in this rulemaking is contained in Sections 4, 303, 614, and 615 of the Communications Act of 1934, as amended, 47 U.S.C. 154, 303, 534, and 535.

3. Description and Estimate of the Number of Small Entities to Which the Proposals Will Apply

28. The RFA directs the Commission to provide a description of and, where feasible, an estimate of the number of small entities that will be affected by the proposed rules if adopted.[84] The RFA generally defines the term ''small entity'' as having the same meaning as the terms ''small business,'' ''small organization,'' and ''small governmental jurisdiction.''[85] In addition, the term ''small business'' has the same meaning as the term ''small business concern'' under the Small Business Act.[86] A ''small business concern'' is one which: (1) Is independently owned and operated; (2) is not dominant in its field of operation; and (3) satisfies any additional criteria established by the Small Business Administration (SBA).[87] The rule changes proposed herein will directly affect small television broadcast stations and small cable operators. A description of these small entities, as well as an estimate of the number of such small entities, is provided below.

29. *Television Broadcasting.* The SBA defines a television broadcasting station as a small business if such station has no more than $14.0 million in annual receipts.[88] Business concerns included in this industry are those ''primarily engaged in broadcasting images together with sound.''[89] The Commission has

[76] Viewability Order at para. 16.

[77] Fourth Report & Order at paras. 11–12.

[78] *Id.* at paras. 12, 18.

[79] See Viewability Order, at para. 16; Fourth Report and Order, at para. 11.

[80] Paperwork Reduction Act of 1995 (''PRA''), Public Law 104–13, 109 Stat 163 (1995) (codified in Chapter 35 of Title 44 U.S.C.).

[81] *See* 5 U.S.C. 603. The RFA, *see* 5 U.S.C. 601–612, has been amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (''SBREFA''), Public Law 104–121, Title II, 110 Stat. 857 (1996).

[82] *See* 5 U.S.C. 603(a).

[83] *See id.*

[84] 5 U.S.C. 603(b)(3).

[85] 5 U.S.C. 601(b).

[86] 5 U.S.C. 601(3) (incorporating by reference the definition of ''small-business concern'' in the Small Business Act, 15 U.S.C. 632). Pursuant to 5 U.S.C. 601(3), the statutory definition of a small business applies ''unless an agency, after consultation with the Office of Advocacy of the Small Business Administration and after opportunity for public comment, establishes one or more definitions of such term which are appropriate to the activities of the agency and publishes such definition(s) in the **Federal Register**.''

[87] 15 U.S.C. 632.

[88] *See* 13 CFR 121.201, NAICS Code 515120 (2007).

[89] *Id.* This category description continues, ''These establishments operate television broadcasting studios and facilities for the programming and transmission of programs to the public. These

estimated the number of licensed commercial television stations to be 1,392.[90] According to Commission staff review of the BIA/Kelsey, MAPro Television Database (''BIA'') as of April 7, 2010, about 1,015 of an estimated 1,380 commercial television stations [91] (or about 74 percent) have revenues of $14 million or less and, thus, qualify as small entities under the SBA definition. The Commission has estimated the number of licensed noncommercial educational (NCE) television stations to be 390.[92] We note, however, that, in assessing whether a business concern qualifies as small under the above definition, business (control) affiliations [93] must be included. Our estimate, therefore, likely overstates the number of small entities that might be affected by our action, because the revenue figure on which it is based does not include or aggregate revenues from affiliated companies. The Commission does not compile and otherwise does not have access to information on the revenue of NCE stations that would permit it to determine how many such stations would qualify as small entities.

30. In addition, an element of the definition of ''small business'' is that the entity not be dominant in its field of operation. We are unable at this time to define or quantify the criteria that would establish whether a specific television station is dominant in its field of operation. Accordingly, the estimate of small businesses to which rules may apply do not exclude any television station from the definition of a small business on this basis and are therefore over-inclusive to that extent. Also, as noted, an additional element of the definition of ''small business'' is that the entity must be independently owned and operated. We note that it is difficult at times to assess these criteria in the context of media entities and our estimates of small businesses to which they apply may be over-inclusive to this extent.

31. *Cable and Other Program Distribution.* Since 2007, these services have been defined within the broad economic census category of Wired Telecommunications Carriers; that category is defined as follows: ''This industry comprises establishments primarily engaged in operating and/or providing access to transmission facilities and infrastructure that they own and/or lease for the transmission of voice, data, text, sound, and video using wired telecommunications networks. Transmission facilities may be based on a single technology or a combination of technologies.'' [94] The SBA has developed a small business size standard for this category, which is: All such firms having 1,500 or fewer employees.[95] According to Census Bureau data for 2007, there were a total of 955 firms in this previous category that operated for the entire year.[96] Of this total, 939 firms had employment of 999 or fewer employees, and 16 firms had employment of 1000 employees or more.[97] Thus, under this size standard, the majority of firms can be considered small and may be affected by rules adopted pursuant to the Fourth FNPRM.

32. *Cable Companies and Systems.* The Commission has developed its own small business size standards, for the purpose of cable rate regulation. Under the Commission's rules, a ''small cable company'' is one serving 400,000 or fewer subscribers, nationwide.[98] Industry data indicate that, of 1,076 cable operators nationwide, all but eleven are small under this size standard.[99] In addition, under the Commission's rules, a ''small system'' is a cable system serving 15,000 or fewer subscribers.[100] Industry data indicate that, of 7,208 systems nationwide, 6,139 systems have under 10,000 subscribers, and an additional 379 systems have 10,000–19,999 subscribers.[101] Thus, under this second size standard, most cable systems are small and may be affected by rules adopted pursuant to the Fourth FNPRM.

33. *Cable System Operators.* The Act also contains a size standard for small cable system operators, which is ''a cable operator that, directly or through an affiliate, serves in the aggregate fewer than 1 percent of all subscribers in the United States and is not affiliated with any entity or entities whose gross annual revenues in the aggregate exceed $250,000,000.'' [102] The Commission has determined that an operator serving fewer than 677,000 subscribers shall be deemed a small operator, if its annual revenues, when combined with the total annual revenues of all its affiliates, do not exceed $250 million in the aggregate.[103] Industry data indicate that, of 1,076 cable operators nationwide, all but ten are small under this size standard.[104] We note that the Commission neither requests nor collects information on whether cable system operators are affiliated with entities whose gross annual revenues exceed $250 million,[105] and therefore we are unable to estimate more accurately the number of cable system operators that would qualify as small under this size standard.

34. *Open Video Services.* The open video system (''OVS'') framework was established in 1996, and is one of four statutorily recognized options for the provision of video programming

establishments also produce or transmit visual programming to affiliated broadcast television stations, which in turn broadcast the programs to the public on a predetermined schedule. Programming may originate in their own studios, from an affiliated network, or from external sources.'' Separate census categories pertain to businesses primarily engaged in producing programming. *See* Motion Picture and Video Production, NAICS code 512110; Motion Picture and Video Distribution, NAICS Code 512120; Teleproduction and Other Post-Production Services, NAICS Code 512191; and Other Motion Picture and Video Industries, NAICS Code 512199.

[90] *See* News Release, ''Broadcast Station Totals as of December 31, 2009,'' 2010 WL 676084 (F.C.C.) (dated Feb. 26, 2010) (''*Broadcast Station Totals*''); also available at *http://hraunfoss.fcc.gov/edocs_public/attachmatch/DOC-296538A1.pdf.*

[91] We recognize that this total differs slightly from that contained in *Broadcast Station Totals, supra* note 83; however, we are using BIA's estimate for purposes of this revenue comparison.

[92] See *Broadcast Station Totals, supra* note 83.

[93] ''[Business concerns] are affiliates of each other when one concern controls or has the power to control the other or a third party or parties controls or has to power to control both.'' 13 CFR 121.103(a)(1).

[94] U.S. Census Bureau, 2007 NAICS Definitions, ''517110 Wired Telecommunications Carriers'' (partial definition), *http://www.census.gov/naics/2007/def/ND517110.HTM#N517110.*

[95] 13 CFR 121.201, NAICS code 517110 (2007).

[96] U.S. Census Bureau, 2007 Economic Census, Subject Series: Information, Table 5, Employment Size of Firms for the United States: 2007, NAICS code 5171102 (issued Nov. 2010).

[97] *See id.*

[98] *See* 47 CFR 76.901(e). The Commission determined that this size standard equates approximately to a size standard of $100 million or less in annual revenues. *See Implementation of Sections of the 1992 Cable Television Consumer Protection and Competition Act: Rate Regulation,* MM Docket Nos. 92–266, 93–215, Sixth Report and Order and Eleventh Order on Reconsideration, 10 FCC Rcd 7393, 7408 para. 28 (1995).

[99] These data are derived from R.R. Bowker, Broadcasting & Cable Yearbook 2006, ''Top 25 Cable/Satellite Operators,'' pages A–8 & C–2 (data current as of June 30, 2005); Warren Communications News, Television & Cable Factbook 2006, ''Ownership of Cable Systems in the United States,'' pages D–1805 to D–1857.

[100] *See* 47 CFR 76.901(c).

[101] Warren Communications News, Television & Cable Factbook 2006, ''U.S. Cable Systems by Subscriber Size,'' page F–2 (data current as of Oct. 2005). The data do not include 718 systems for which classifying data were not available.

[102] 47 U.S.C. 543(m)(2); *see also* 47 CFR 76.901(f) & nn.1–3.

[103] 47 CFR 76.901(f); *see FCC Announces New Subscriber Count for the Definition of Small Cable Operator,* Public Notice, 16 FCC Rcd 2225 (Cable Services Bureau 2001).

[104] These data are derived from R.R. Bowker, Broadcasting & Cable Yearbook 2006, ''Top 25 Cable/Satellite Operators,'' pages A–8 & C–2 (data current as of June 30, 2005); Warren Communications News, Television & Cable Factbook 2006, ''Ownership of Cable Systems in the United States,'' pages D–1805 to D–1857.

[105] The Commission does receive such information on a case-by-case basis if a cable operator appeals a local franchise authority's finding that the operator does not qualify as a small cable operator pursuant to 76.901(f) of the Commission's rules.

services by local exchange carriers.[106] The OVS framework provides opportunities for the distribution of video programming other than through cable systems. Because OVS operators provide subscription services,[107] OVS falls within the SBA small business size standard covering cable services, which is ''Wired Telecommunications Carriers.'' [108] The SBA has developed a small business size standard for this category, which is: All such firms having 1,500 or fewer employees. According to Census Bureau data for 2007, there were a total of 3,188 firms in this previous category that operated for the entire year.[109] Of this total, 3,144 firms had employment of 999 or fewer employees, and 44 firms had employment of 1,000 employees or more.[110] Thus, under this size standard, most cable systems are small and may be affected by rules adopted pursuant to the Fourth FNPRM. In addition, we note that the Commission has certified some OVS operators, with some now providing service.[111] Broadband service providers (''BSPs'') are currently the only significant holders of OVS certifications or local OVS franchises.[112] The Commission does not have financial or employment information regarding the entities authorized to provide OVS, some of which may not yet be operational. Thus, again, at least some of the OVS operators may qualify as small entities.

4. Description of Projected Reporting, Recordkeeping, and Other Compliance Requirements for Small Entities

35. The *Fourth FNPRM* seeks comment on a rule revision that would extend for three years the existing viewability rule, which would affect small television broadcast stations and cable operators by requiring cable systems to continue to make must-carry broadcast signals viewable in analog on hybrid systems, or in digital on all-digital systems. This should impose no compliance burden on small cable systems, because they will simply be continuing current practices, and should continue to have a positive impact on small television broadcast stations. The *Fourth FNPRM* also seeks comment on extending the HD carriage exemption, which would affect small television broadcast stations and cable operators. It is beneficial to small cable operators by providing them with flexibility, and imposes no compliance burden on small television broadcast stations who need take no action as a result of this proposed extension.

5. Steps Taken To Minimize Significant Economic Impact on Small Entities, and Significant Alternatives Considered

36. The RFA requires an agency to describe any significant alternatives that it has considered in reaching its proposed approach, which may include the following four alternatives (among others): (1) The establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities; (2) the clarification, consolidation, or simplification of compliance or reporting requirements under the rule for small entities; (3) the use of performance, rather than design, standards; and (4) an exemption from coverage of the rule, or any part thereof, for small entities.[113] We seek comment on the applicability of any of these alternatives to affected small entities.

37. The requirements proposed in the *Fourth FNPRM* would in most cases create minimal economic impact on small entities, and in some cases would provide positive impact. The viewability requirement has been mandated by Congress, and continuation of the current rule could minimize economic impact on small cable systems and television broadcast stations by maintaining the status quo and not requiring any additional investment in engineering or legal services. The HD carriage exemption does not impose a negative economic impact on any small cable operator, and provides a positive economic impact to any operator of a system that chooses to take advantage of the exemption. The exemption does not impose any significant burdens on small television stations. We invite small entities to submit comment on the impact of extension or sunset of the viewability rule and the HD carriage exemption, and on how the Commission could further minimize potential burdens on small entities.

6. Federal Rules That May Duplicate, Overlap, or Conflict With the Proposed Rules

38. None.

VII. Ordering Clauses

39. *It is ordered* that, pursuant to sections 4, 303, 614, and 615 of the Communications Act of 1934, as amended, 47 U.S.C. 154, 303, 534, and 535, this *Fourth Further Notice Of Proposed Rulemaking* and *Declaratory Order* is *adopted.*

40. *It is further ordered* that, pursuant to sections 5(d) of the Administrative Procedure Act, Sections 4, 303, 614, and 615 of the Communications Act of 1934, as amended, and 1.2 of the Commission's rules, 5 U.S.C. 554(e); 47 U.S.C. 154, 303, 534, 535; 47 CFR 1.2, the viewability rule and the HD Carriage exemption will be in effect up to and until June 12, 2012, absent further Commission action.

41. *It is ordered* that the Reference Information Center, Consumer and Governmental Affairs Bureau, shall send a copy of this Notice of Proposed Rulemaking, including the Initial Regulatory Flexibility Analysis, to the Chief Counsel for Advocacy of the Small Business Administration.

List of Subjects in 47 CFR Part 76

Administrative practice and procedure, Cable television, Equal employment opportunity, Political candidates, Reporting and recordkeeping requirements.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

For the reasons discussed in the preamble, the Federal Communications Commission proposes to amend 47 CFR part 76 as follows:

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[106] 47 U.S.C. 571(a)(3)–(4). See Annual Assessment of the Status of Competition in the Market for the Delivery of Video Programming, MB Docket No. 06–189, Thirteenth Annual Report, 24 FCC Rcd 542, 606 para. 135 (2009) (''Thirteenth Annual Cable Competition Report'').

[107] *See* 47 U.S.C. 573.

[108] U.S. Census Bureau, 2007 NAICS Definitions, ''517110 Wired Telecommunications Carriers''; *http://www.census.gov/naics/2007/def/ND517110.HTM#N517110.*

[109] U.S. Census Bureau, 2007 Economic Census, Subject Series: Information, Table 5, Employment Size of Firms for the United States: 2007, NAICS code 5171102 (issued Nov. 2010).

[110] *See id.*

[111] A list of OVS certifications may be found at *http://www.fcc.gov/mb/ovs/csovscer.html.*

[112] *See Thirteenth Annual Cable Competition Report,* 24 FCC Rcd at 606–07 para. 135. BSPs are newer firms that are building state-of-the-art, facilities-based networks to provide video, voice, and data services over a single network.

[113] 5 U.S.C. 603(c)(1)–(c)(4).

PART 76—MULTICHANNEL VIDEO AND CABLE TELEVISION SERVICE

1. The authority citation for part 76 continues to read as follows:

Authority: 47 U.S.C. 151, 152, 153, 154, 301, 302, 302a, 303, 303a, 307, 308, 309, 312, 315, 317, 325, 339, 340, 341, 503, 521, 522, 531, 532, 534, 535, 536, 537, 543, 544, 544a, 545, 548, 549, 552, 554, 556, 558, 560, 561, 571, 572, 573.

2. Section 76.56 is amended by revising paragraph (d)(5) to read as follows:

§ 76.56 Signal carriage obligations.

* * * * *

(d) * * *

(5) The requirements set forth in paragraph (d)(3) of this section shall cease to be effective June 12, 2015, unless the Commission extends the requirements prior to that date.

* * * * *

The following pages will not appear in the Code of Federal Regulations.

Appendix

325 Data Analysis for Viewability Sunset

1. The FCC collects data from cable operators annually on the ''Annual Report of Cable Systems'' also called ''Form 325.'' Through this form, the FCC collects basic operational information from cable television systems nationwide, including data about their architecture, capacity and number of subscribers. Each year the FCC designates a sample of cable systems having fewer than 20,000 subscribers and all systems having 20,000 or more subscribers to file Form 325. Staff performed an analysis of the Form 325 data from the 2010 filing year for use in the viewability proceeding.

Must Carry/Retransmission Consent

2. Filers of Form 325 report information on the channels carried, including for broadcast channels whether the channel is carried pursuant to a must-carry designation or a retransmission consent agreement. Staff analyzed the 2010 filings and found that approximately 780 of 2000 full-service and low-power stations elected or defaulted to must carry.

3. To make this approximation, staff first extracted from the Form 325 database all records where a cable operator marked a channel as either retransmission-consent or must-carry. A single broadcast station often has multiple entries on the Form 325 if the operator carried multiple versions to comply with the viewability requirements or if the operator chose to carry multicast streams of a single station. For example, WXXX–TV was reported 92 times by 25 cable systems with 7 different spellings.

WXXX
WXXX WEATHER NOW
WXXX 7
WXXX–TV
WXXX WEATHER
WXXX HD
WXXX RETRO TV NETWORK

4. Next, the staff reduced the number of entries per cable system to one by considering that if at any one of those entries was marked as must-carry, then that station was must-carry on that cable system. The dataset for WXXX was then reduced to one report for each of the 25 cable systems. If any one of the entries for a cable system was marked as must-carry, the report for that cable system was must-carry.

5. Due to either different elections on different cable systems or accidental misreporting by cable operators, many stations had a mixture of must-carry and retransmission-consent reports.

	Must-Carry	Retrans-mission-Consent
WXXX	2	23

6. The staff aggregated the reports, and if operators reported a station as must-carry as or more often as operators reported that station as retransmission-consent, the staff considered that station to prefer must-carry. In this case, the majority of cable systems reports retransmission consent, so WXXX was assigned a single preference:

WXXX	Retransmission-Consent

7. The process was repeated for each of the approximately 2000 broadcast stations listed in the 325 reports. In the event of an equal number of systems reporting must-carry and retransmission consent, the station was considered to have chosen must-carry.

Subscribers Served by Hybrid Cable Systems

8. Staff analyzed the ''number of digital channels activated'' and ''number of analog channels activated'' data fields in the Form 325 reports from filing year 2010. A hybrid system has at least one activated analog channel and at least one activated digital channel. As the Form 325 is collected by a sample of cable systems, staff performed the below analysis to determine that 56.8 million of the 62 million cable subscribers are on hybrid systems.

9. Of the 565 systems that reported more than 20,000 subscribers, 542 were hybrid systems, with those systems serving 46.6 million subscribers. No scaling factor was necessary as reports must be filed by all systems with more than 20,000 subscribers.

10. Of the 249 systems that reported between 5,000 and 20,000 subscribers, 233 were hybrid systems serving 2.7 million subscribers. A representative sample of systems with between 5,000 and 20,000 is asked to file reports each year. Based on previous years' Form 325 reports and other research, staff estimated that there are 451 such systems in total. When the data was extrapolated, staff estimated that 422 of the 451 systems are hybrid. Thus, the 2.7 million subscribers were scaled by a multiple of (422/233), yielding an estimated total of 4.9 million subscribers.

11. Of the 154 systems that reported fewer than 5000 subscribers, 91 were hybrid systems serving 184 thousand subscribers. A representative sample of systems with fewer than 5000 subscribers is asked to file reports each year. Based on previous years' Form 325 reports and other research, staff estimated that there are 4450 such systems in total. When the data was extrapolated, staff estimated that 2630 of the 4450 systems are hybrid. When scaled by a multiple of (2630/91), staff estimated that there are a total of 5.3 million subscribers served by these systems.

12. Staff summed the total number of subscribers served by hybrid systems and came up with a result of 56.8 million such subscribers (46.6 million + 4.9 million + 5.3 million).

Staff used a similar process as described above to estimate the total number of cable subscribers in the U.S. as approximately 62 million. This total is close to other publicly available estimates of cable subscribers.

[FR Doc. 2012–3703 Filed 2–15–12; 8:45 am]

BILLING CODE 6712–01–P

Federal Register

Vol. 77, No. 32

Thursday, February 16, 2012

Notices

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

AFRICAN DEVELOPMENT FOUNDATION

Board of Directors Meeting

Time: Tuesday, February 28, 2012, 8:45 a.m. to 1 p.m.

Place: African Development Foundation, Conference Room, 1400 I Street NW., Suite 1000, Washington, DC 20005.

Date: Tuesday, February 28, 2012.

Status:

1. Open session, Tuesday, February 28, 2012, *8:45 a.m. to 11:45 a.m.;* and
2. Closed session, Tuesday, February 28, 2012, *12 p.m. to 1 p.m.*

Due to security requirements and limited seating, all individuals wishing to attend the open session of the meeting must notify Sarah Conway at (202) 233–8811 or *sconway@usadf.gov* of your request to attend by 5 p.m. on Thursday, February 23, 2012.

Lloyd O. Pierson,

President & CEO, USADF.

[FR Doc. 2012–3593 Filed 2–15–12; 8:45 am]

BILLING CODE 6117–01–P

DEPARTMENT OF AGRICULTURE

Food and Nutrition Service

Agency Information Collection Activities: Proposed Collection; Comments Request—Study of Organizations Providing or Administering SNAP Incentives at Farmers' Markets

AGENCY: Food and Nutrition Service, USDA.

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice invites the public and other public agencies to comment on this proposed information collection. This is a revision to a previous data collection to understand better the shopping patterns of SNAP participants at farmers' markets. The purpose of this collection is for the Food and Nutrition Service to understand how private organizations operate Supplemental Nutrition Assistance Program (SNAP) financial incentive programs for clients purchasing fruits and vegetables at farmers' markets. Information collected will be used to examine how these organizations design, operate, and evaluate incentive programs to encourage SNAP clients to shop for fruits and vegetables at farmers' markets. It will also assist in assessing how much these programs influence the purchase of fruits and vegetables at farmers' markets using SNAP benefits.

DATES: Written comments must be received on or before April 16, 2012.

ADDRESSES: Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden on the proposed collection of information, including the validity of the methodology and assumptions that were used; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

Comments may be sent to: Steven Carlson, Office of Research and Analysis, Food and Nutrition Service/USDA, 3101 Park Center Drive, Room 1014, Alexandria, VA 22302. Comments may also be submitted via fax to the attention of Steven Carlson at 703–305–2576 or via email to *Steve.Carlson@fns.usda.gov*. Comments will also be accepted through the Federal eRulemaking Portal. Go to *http://www.regulations.gov* and follow the online instructions for submitting comments electronically.

All written comments will be open for public inspection at the Office of Research and Analysis, Food and Nutrition Service during regular business hours (8:30 a.m. to 5 p.m. Monday through Friday) at 3101 Park Center Drive, Room 1014, Alexandria, Virginia 22302.

All responses to this notice will be summarized and included in the request for Office of Management and Budget approval. All comments will be a matter of public record.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of this information collection should be directed to Steven Carlson at 703–305–2017.

SUPPLEMENTARY INFORMATION:

Title: Study of Organizations Providing or Administering SNAP Incentives at Farmers' Markets.

OMB Number: 0584–0564.

Expiration Date of Approval: November 30, 2014.

Abstract: The USDA, Food and Nutrition Service (FNS), is undertaking initiatives to improve access to healthy foods among nutrition assistance program participants. Among these are steps to support access to fresh fruits and vegetables through farmers' markets. The overall objective of this collection is to understand how private organizations provide and administer financial incentives for SNAP participants shopping at farmers' markets. In addition, this collection aims to assess how well these incentive programs work concerning the purchase of fresh fruits and vegetables at farmers' markets by SNAP participants. The two main study objectives are to: (1) Describe and compare how private organizations design, operate, and evaluate incentive program for SNAP clients at farmers' markets; and (2) describe and compare the performance, outcomes and/or impacts of each incentive program for SNAP clients operated during 2012 based upon the FNS SNAP Anti-Fraud Locator for EBT Redemption Transactions (ALERT) data and incentive organization self-evaluation data.

This study is not intended to be nationally representative. Organizations to be included in this study will be chosen from a list of private organizations that is developed based on responses received from farmers' market managers responding to the FNS study, Nutrition Assistance in Farmers' Markets: Understanding Current Operations (76 FR 79646, 12/22/11). To assist in the selection process, the list will tentatively categorize the organizations (Business-for and not-for-profit) into three groups:

(1) Type I: fairly large organizations that provide grant money to other organizations that administer incentive program for SNAP clients;

(2) Type II: smaller than the Type I organizations, Type II organizations distribute the SNAP financial incentives to farmers' markets and administer the incentive program for SNAP clients in the markets that they support; and

(3) Type III: local organizations that provide money for incentive program for SNAP clients.

Further stratification of the frame may be made based on whether the organizations also provide non-financial support. Non-financial support might include providing information and technical assistance for implementing or managing incentive program for SNAP clients or providing staff to work at the farmers' markets and assist with the management of the programs onsite.

There are two main data collection activities for this study. They include:

• Conducting a telephone interview with each of one to three key staff at selected organizations that provide and/or administer farmers' market SNAP incentives. The interview is designed to gather qualitative data to better understand the:

○ Relationship of the organizations to the farmers' markets that obtain incentive funds for SNAP clients;

○ Primary mission of the organizations and their history with SNAP;

○ Source of the financial support for the organizations' incentive program for SNAP clients, and whether other types of support are offered;

○ Number of markets a specific organization supported in 2012;

○ Selection process and requirements for farmers' markets to be awarded incentive dollars for distribution to SNAP clients;

○ Factors that make it difficult to implement and manage incentive programs; and

○ Characteristics of successful incentive programs.

The telephone interview will also capture information on whether the organizations maintain and/or collect information on the performance of their incentive program. This self-evaluation data may include information regarding the number of incentives redeemed by markets with an incentive program, vendor satisfaction with the program, and/or data used for assessing the impact of these programs on farmers' market sales and SNAP participation at farmers' markets.

• Collecting and evaluating self-evaluation data of participating organizations. Organizations identified during the telephone interviews as maintaining data on their incentive program for SNAP clients will be asked to share this data for the purpose of this research study. Self-evaluation data shared by organizations may include for example, the number of other organizations or farmers' markets that they awarded or are managing financial incentive programs for, the volume of SNAP incentive redemptions, dollar amount of unredeemed incentives, and other information. These data will help identify differences across incentive programs with respect to performance in 2012. In combination, the self-evaluation data, organizational and incentive program characteristics obtained through interviews, and ALERT data, will inform how such incentive programs for SNAP clients may work best in the context of individual markets.

Affected Public: Respondent groups identified include individuals working for organizations (Businesses for- and not for-profit. Note: preliminary research suggests that all organizations in the sample will be not for-profit businesses. However, the study leaves open the possibility that some for-profit businesses will be part of the sample) that provide or administer financial incentives at farmers' markets for use with SNAP clients.

Estimated Number of Respondents: The total number of respondents is 225 individuals at 115 organizations. This includes up to 3 individuals working for each of the 15 Type I and 40 Type II organizations, and 1 individual at each of the 45 Type III organizations. Out of the 225 individuals, it is estimated that 10 percent from each type of organization, a total of 23 individual, invited to participate will refuse (2.5 Type I, 8 Type II, and 4.5 Type III organizations). If a selected organization refuses to participate, another similar organization will be selected as a replacement.

Estimated Number of Responses per Respondent: One time.

Estimated time per Response: For 110 individuals participating from Type I and II organizations, and 45 individuals from Type III organizations, the telephone interview will take 60 minutes (1 hour) to complete. For 55 participating individuals (the Type I and II organizational leaders), the telephone interview will take 20 minutes (0.33 hours) to complete. It is estimated that 23 organizational leaders (from 15 organizations) that refuse to participate will spend approximately 15 minutes (0.25 hours) on the telephone. Further, of the 90 organizations that participate and complete the telephone interviews, 80 organizations will agree to provide self-evaluation data for their programs. To provide the data, it will take 120 minutes (2.0 hours) of a staff member's time
(1 from each organization). For the 10 organizations that elect not to share their self-evaluation data, it will take 30 minutes (0.50) hours of a staff member's time (1 from each organization).

Estimated Total Annual Burden on Respondents: 341.9 hours.

Affected Public	Respondent	Estimated number of respondents	Responses annually per respondent	Total annual responses	Estimated average number of hours per response	Estimated total annual hours of response burden
Business (for/not-for-profit).	Type I Organization Telephone Interviews					
	Leaders Completed	15	1	15	0.33	4.95
	Leaders Non-response	2.5	1	2.5	0.25	0.625
	Staff *	30	1	30	1.00	30.00
	Subtotal Type I	45	1	47.5		35.575
	Type II Organization Telephone Interviews					
	Leaders Completed	40	1	40	0.33	13.2

Affected Public	Respondent	Estimated number of respondents	Responses annually per respondent	Total annual responses	Estimated average number of hours per response	Estimated total annual hours of response burden
	Leaders Non-response	8	1	8	0.25	2
	Staff *	80	1	80	1.00	80
	Subtotal Type II	120	1	128	....	95.2
	Type III Organization Telephone Interviews					
	Leaders or Staff Completed	45	1	45	1.00	45
	Leaders or Staff Non-response	4.5	1	4.5	0.25	1.125
	Subtotal Type III	45	1	49.5	....	46.125
	GRAND TOTAL	210	....	225	....	176.9
	Provision of Organizational Self-Evaluation Data Type I, II, and III Organizations					
	Number of Organizations Providing Self-Evaluation Data.	80	1	80	2.00	160
	Number of Organizations that Refuse to Provide Self-Evaluation Data.	10	1	10	0.50	5
	Total	90	1	90	....	165

* 100% response anticipated for this group.

Dated: February 7, 2012.

Audrey Rowe,

Administrator,

Food and Nutrition Service.

[FR Doc. 2012–3619 Filed 2–15–12; 8:45 am]

BILLING CODE 3410–30–P

DEPARTMENT OF AGRICULTURE

Forest Service

Los Padres National Forest: California; Environmental Impact Statement for the Removal of the Noxious Weed Tamarisk on the Los Padres National Forest

AGENCY: Forest Service, USDA.

ACTION: Notice of intent to prepare an environmental impact statement.

SUMMARY: The USDA, Forest Service, Los Padres National Forest, gives notice of intent to conduct analysis and prepare an Environmental Impact Statement (EIS) for the removal of the noxious weed Tamarisk across the Los Padres National forest: This notice announces the beginning of scoping, describes the proposed action, decisions to be made, and estimates the dates for filing the draft and final EIS. This notice also provides information concerning public participation, and the names and addresses of the Agency officials who can provide information.

DATES: Comments concerning the scope of the analysis will be received for 45 days from publication in the **Federal Register**. The draft environmental impact statement is expected in summer of 2012 and the final environmental impact statement is expected late 2012.

ADDRESSES: Send written comments to Los Padres National Forest, 6755 Hollister Avenue, Suite 150, Goleta, CA 93117, attention: Lloyd Simpson, Forest Botanist. Comments may also be sent via e-mail to: *comments-pacificsouthwest-los-padres-ojai@fs.fed.us*, or via facsimile to 805–646–0408.

Comments received in response to this solicitation, including names and addresses of those who comment, will be part of the public record for this proposed action.

FOR FURTHER INFORMATION CONTACT: Questions about the proposed action may be directed to Project Team Leader, Lloyd Simpson, Los Padres National Forest, Ojai Ranger District, 1190 E. Ojai Ave., Ojai, CA 93023; or by telephone: (805) 646–4348 ext. 316. E-mail: *comments-pacificsouthwest-los-padres-ojai@fs.fed.us*.

Individuals who use telecommunication devices for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 between 8 a.m. and 8 p.m., Eastern Time, Monday through Friday.

SUPPLEMENTARY INFORMATION:

Purpose and Need for Action

There is a need to eradicate the noxious weed tamarisk from Piru Creek, Lockwood Creek, Cuyama River, Santa Ynez River, Sisquoc River, and Arroyo Seco River in order to restore and maintain habitat for riparian dependent species such as the federally listed arroyo toad, California red-legged frog, and steelhead trout. The purpose of this project is to eradicate tamarisk in a timely manner and with an approach that is pest-specific, cost effective, and safe for the human and aquatic environments.

The project area is on the Los Padres National Forest in portions of the Piru Creek, Lockwood Creek, Cuyama River, Santa Ynez River, Sisquoc River, and Arroyo Seco River watersheds. The analysis area covers 4,247 acres and 368 miles of perennial and intermittent streams. Infestations of tamarisk occurring in these streams and their tributaries within the analysis area are targeted for removal.

For fish and wildlife, direction is provided to maintain fisheries habitat for viable populations of native fish species and to prevent the destruction or adverse modification of habitat essential to threatened, endangered, or sensitive species. The Forest Plan states that ''management activities or practices may occur in riparian areas as long as habitat and species diversity of the area is maintained in a healthy state'' and that ''habitat improvement will enhance conditions for sensitive, threatened, and endangered species.''

Proposed Action

The Los Padres National Forest (LPNF) proposes to control the invasive species tamarisk in portions of the Piru Creek, Lockwood Creek, Cuyama River, Santa Ynez River, Sisquoc River, and Arroyo Seco River watersheds. This action will result in the improvement of riparian ecosystems that have been impacted by the invasion of tamarisk.

Tamarisk has replaced the native riparian plant community of willows, cottonwoods and other desirable native riparian species. Its water-consuming ability has reduced the surface water available to wildlife. The best management strategy is to enact control measures now before the tamarisk infestations become any larger.

Successful invasive species control programs are implemented at the landscape level, particularly within watersheds for species that colonize stream courses. Partnerships are especially important for accomplishing weed control. Volunteers have worked for many years on the Los Padres to remove and control tamarisk. They will continue to be part of this effort.

Tamarisk infestations have various impacts on a number of federally listed threatened (FT) and endangered (F–E) species, as well as some Region 5 Forest Service Sensitive (R5–S) species. Federally listed endangered Least Bell's vireo and Southwestern Willow Flycatcher have been known to nest in large groves of habitat dominated by tamarisk, but this is not likely in the Los Padres NF given the scattered nature of the present tamarisk populations. However, it is well documented that tamarisk removal will restore natural habitat for these birds as well as arroyo toad (F–E), California red-legged frog (F–T), southwestern pond turtle (R5–S), two-striped garter snake (R5–S) and steelhead trout (both F–E and F–T) stocks.

This project is designed to eradicate current infestations of Tamarisk (Tamarix ramosissima, T chinensis, T gallica, T parviflora) and to prevent its further spread on National Forest System land. Tamarisk is a nonnative invasive tree-shrub that can grow in dense patches, out-compete native vegetation, change soil chemistry by depositing salts in deep ground water on the soil surface, and remove large amounts of water from streams and riparian areas via evapo-transpiration through its foliage. This project covers portions of the Piru Creek, Lockwood Creek, Cuyama River, Santa Ynez River, Sisquoc River, and Arroyo Seco River watersheds.

The current tamarisk infestation covers 368 miles or 4,247 acres of riparian habitat on NFS lands. The goal is to implement control measures now before tamarisk becomes a larger problem in riparian ecosystems.

The methods of tamarisk eradication have several constraints in this project: (1) Many treatment areas are very steep, making access and logistics difficult. There is no motorized access to most of the project area, much of it is in Congressionally designated Wilderness. All supplies and equipment must either be packed or flown in. Pile-burning cut tamarisk stems is not feasible due to the logistics of getting crews and suppression resources down into the canyons to do it. (2) There are few suitable areas to relocate tamarisk stems for disposal via burn piles. (3) There is habitat known for Least Bell's Vireo and Southwestern Willow Flycatcher, two federally endangered birds in the Piru creek watershed. The habitat area contains scattered tamarisk within the riparian vegetation.

The proposed action is a combination of tamarisk treatment methods designed to be as light on the land as possible and at the same time cost and labor efficient. The methods used will be a combination of hand treatments, herbicide applications, and biological control. Tamarisk seedlings will be removed by hand by pulling and placing them where they cannot reestablish. Herbicides are essential to meet the project objectives. Tamarisk will re-sprout if simply cut down and/or burned. Herbicide treatments are the most effective and the most efficient control method currently available. Herbicide use will be consistent with the Forest Service Pesticide Use Policy, will be in compliance with state and federal regulations, will follow Region 5 Best Management Practices for Vegetation Manipulation, the Region 5 Supplement for Pesticide-Use Management and Coordination, and the Forest Plan guidance including the Supplement to Soil and Water Conservation Practices FSH 2509.22–2005–1. A bio-control insect bred to assist in the treatment and control of tamarisk infestations is currently available. While tamarisk distribution across NFS land may be too spread out to maintain effective populations of a control insect, use of the insect may be appropriate in areas where there is higher tamarisk density.

Herbicide treatments will be restricted to ground-based/hand applications only; NO AERIAL SPRAYING is being proposed.

Seedlings and young plants will be hand-pulled where possible and removed from the riparian area and placed in the sun minimizing soil contact with the roots. Experience with hand pulling has shown that only plants 1 foot tall or less can be successfully removed. We will begin removing the younger plants on the boundaries of infestations and do as much as we can each year.

Large tamarisk within 10 horizontal feet of standing or running water will be treated with imazapyr (Habitat or similar formulation). Treatment type will depend on size of the individual tamarisk plant and the access available to do the treatment. Cut plant material will be removed from the waterway but left in small piles as wildlife habitat.

Treatment methods are:

Cut Stump Treatment: Tree trunks are cut near ground level with handsaws or chainsaws and then stumps are hand coated with the herbicide, surfactant and colorant using sponge brushes. The mixture is quickly absorbed by the plant's phloem and transported to the root; if the herbicide mixture is applied immediately (2–10 minutes), 85–95% control is possible.

Frill Treatment: With this method, a hatchet is used to cut downward into the water-conducting tissue (phloem) of standing trees. This treatment would be done using a Hypo-Hatchet to directly inject a pre-set amount of herbicide directly into the tree. Usually one injection is made for every inch of stem diameter evenly spaced around the circumference.

For plants beyond the 10 horizontal feet of standing or running water, another herbicide, triclopyr (Garlon 4 or similar formulation) may be used. Triclopyr is not labeled for use around water and would only be used on upland plants. Treatments would be similar to imazapyr and based on plant size. Cut material will be disposed of in the same way as the cut riparian tamarisk described earlier.

Resource Protection Measures

The following resource protection measures would be employed under all action alternatives:

Water Quality: Water quality would be protected following measures described in the Best Management Practices. Best Management Practices would be implemented during all activities associated with this proposed action. Best Management Practices (BMPs) are measures developed cooperatively with the Forest Service and the California State Water Quality Control Board to control non-point source pollution on National Forest

System lands. Many BMPs are available for use and can be tailored to accommodate site-specific conditions. A monitoring protocol for this project will be included in the project implementation plan.

Wildlife and Fisheries: A biological assessment/evaluation of all threatened, endangered, and sensitive wildlife and fish species that potentially occur in the project would be drafted to provide an assessment of the impacts of the proposed action. The best management practices above will minimize or eliminate the exposure of wildlife and fisheries to pesticides. The primary effect on federally listed or Forest Service sensitive species will be the physical presence to work crews in occupied habitat. The following resource protection measures would be carried out during project implementation to protect federally listed and R5 Forest Service sensitive species:

- To avoid trampling of arroyo toads and California red-legged frogs, a qualified biologist would conduct a training session for all project personnel prior to conducting the proposed action in habitat for arroyo toads and California red-legged frogs. At a minimum, the training would include a description of the arroyo toad and its habitat, the general provisions of the Endangered Species Act; the necessity for adhering to the provisions of the Act; the penalties associated with violating the provisions of the Act; the general measures that are being implemented to conserve the listed species as they relate to the project; and the access routes to and from project site boundaries within which the treatments may be accomplished.
- In arroyo toad and California red-legged frog habitat, all routes to treatment sites would be identified by a qualified biologist and used repeatedly by workers to minimize trampling of arroyo toads and vegetation.
- Applicators would avoid walking or stepping in water, to the maximum extent possible. They would also avoid spilling herbicide on footwear and clothing to prevent inadvertent contamination if contact with water occurs.
- All access routes and treatment sites within arroyo toad and California red-legged frog habitat would be thoroughly searched for the presence of arroyo toads and California red-legged frog by a qualified biologist, prior to the onset of project activities at each site. This should occur within two weeks of work commencement.
- Arroyo toads and California red-legged frog found within the treatment sites shall be carefully moved outside the immediate work area and released by a qualified biologist permitted by USFWS to handle these species. Animals found within access routes may be moved to appropriate habitat if their avoidance is not practicable. If project activities cease for more than three days within any one treatment site, access routes and treatment areas would be searched again for arroyo toads and California red-legged frog prior to the start of the day's work. Information that includes the date, time of capture, specific location of capture, approximate size, age and health of the individual would be recorded.
- Treatments will be conducted during low stream flow or no stream flow periods of the year to avoid potential impacts to steelhead trout or their spawning redds during the late fall to early winter months.
- If workers encounter aquatic wildlife species other than arroyo toads and California red-legged frog during project implementation they will allow the animal(s) to flee to safe areas out of the work sites or physically move the animals to safe locations.

Sensitive Plants: A biological assessment/evaluation of all threatened, endangered, and sensitive plant species that potentially occur in the project would be drafted to provide an assessment of the impacts of the proposed action. Best Management practices above and the highly targeted application methods being used in this project will minimize the exposure of Forest Service sensitive plant species to herbicide.

Noxious Weeds: Require cleaning of any tools carried into or out of the project area to reduce the risk of noxious weed spread.

Heritage Resources: Areas requiring flagging and avoidance would be identified by a qualified heritage resources manager to the project planner prior to any implementation of project work.

Possible Alternatives

A full range of alternatives will be considered including action and no-action. Alternatives responding to issues generated during the scoping process and interdisciplinary team project development will also be developed and considered. All alternatives will comply with the Los Padres National Forest Land Management Plan.

Responsible Official

Peggy Hernandez, Forest Supervisor, Los Padres National Forest, Goleta California, is the responsible official for the EIS and its Record of Decision. As the Responsible Official, the Forest Supervisor will document the decision and reason for the decision in the Record of Decision. The decision will be subject to Forest Service Appeals Regulations (36 CFR part 215).

Nature of Decision to be Made

The Responsible Official will make a decision considering the following:

1. Whether the proposed action will proceed as proposed, with modifications, or not at all.
2. What associated mitigation measures and monitoring requirements will be required.

Preliminary Issues

Preliminary issues identified include the following:

1. Hand removal is not controlling the current infestations of Tamarisk and herbicides are needed.
2. Use of herbicides and the need to protect water quality and public safety.
3. Presence of listed threatened and endangered species, their habitat, and/or mapped critical habitat.

Scoping Process

This notice of intent initiates the scoping process, which guides the development of the environmental impact statement.

The Forest Supervisor is seeking public and agency comment on the proposed action to identify issues that arise from the proposed action. The issues may lead to other alternatives, or additional mitigation measure and monitoring requirements. In addition to this notice, public scoping letters will be mailed to interested parties.

It is important that reviewers provide their comments at such times and in such a way they are useful to the Agency's preparation of the environmental impact statement. The submission of timely and specific comments can affect a reviewer's ability to participate in subsequent administrative appeal of judicial review.

Dated: February 1, 2012.

Peggy Hernandez,

Forest Supervisor.

[FR Doc. 2012–3534 Filed 2–15–12; 8:45 am]

BILLING CODE P

DEPARTMENT OF COMMERCE

Submission for OMB Review; Comment Request

The Department of Commerce will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the

Paperwork Reduction Act (44 U.S.C. Chapter 35).

Agency: National Oceanic and Atmospheric Administration (NOAA).

Title: Seafood Inspection and Certification Requirements.

OMB Control Number: 0648–0266.

Form Number(s): 89–800, 89–814, 89–819.

Type of Request: Regular submission (extension of a current information collection).

Number of Respondents: 3,339.

Average Hours per Response: Application for inspection, application for appeal of previous inspection results and contract completion or amendment, 5 minutes each; label and specification submission, 30 minutes; HACCP plan, 60 hours; recordkeeping requirements related to an existing plan, 40 hours.

Burden Hours: 8,139.

Needs and Uses: The National Marine Fisheries Service (NMFS) operates a voluntary fee-for-service seafood inspection program (Program) under the authorities of the Agricultural Marketing Act of 1946, as amended, the Fish and Wildlife Act of 1956, and the Reorganization Plan No. 4 of 1970. The regulations for the Program are contained in 50 CFR part 260. The program offers inspection grading and certification services, including the use of official quality grade marks which indicate that specific products have been Federally inspected. Those wishing to participate in the Program must request the services and submit specific compliance information. In July 1992, NMFS announced new inspection services, which were fully based on guidelines recommended by the National Academy of Sciences, known as Hazard Analysis Critical Control Point (HACCP). The information collection requirements fall under § 260.15 of the regulations. These guidelines required that a facility's quality control system have a written plan of the operation, identification of control points with acceptance criteria and a corrective action plan, as well as identified personnel responsible for oversight of the system. The chapter entitled ''Development, Assessment, Approval, and Continuing Compliance Evaluation of HACCP-based Inspection Systems,'' from the NMFS Fishery Products Inspection Manual, describes in detail the requirements for participants choosing to receive NMFS HACCP-based inspection services.

Affected Public: Business or other for-profit organizations.

Frequency: On occasion.

Respondent's Obligation: Required to obtain or retain benefits.

OMB Desk Officer: OIRA_Submission@omb.eop.gov.

Copies of the above information collection proposal can be obtained by calling or writing Jennifer Jessup, Departmental Paperwork Clearance Officer, (202) 482–0336, Department of Commerce, Room 6616, 14th and Constitution Avenue NW., Washington, DC 20230 (or via the Internet at *JJessup@doc.gov*).

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *OIRA_Submission@omb.eop.gov.*

Dated: February 10, 2012.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. 2012–3615 Filed 2–15–12; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Notice of Partially Closed Meeting of the Regulations and Procedures Technical Advisory Committee

The Regulations and Procedures Technical Advisory Committee (RPTAC) will meet March 6, 2012, 9 a.m., Room 3884, in the Herbert C. Hoover Building, 14th Street between Constitution and Pennsylvania Avenues NW., Washington, DC. The Committee advises the Office of the Assistant Secretary for Export Administration on implementation of the Export Administration Regulations (EAR) and provides for continuing review to update the EAR as needed.

Agenda

Public Session

1. Opening remarks by the Chairman.
2. Opening remarks by Bureau of Industry and Security.
3. Export Enforcement update.
4. Regulations update.
5. Working group reports.
6. Automated Export System (AES) update.
7. Presentation of papers or comments by the Public.

Closed Session

8. Discussion of matters determined to be exempt from the provisions relating to public meetings found in 5 U.S.C. app. 2 §§ 10(a)(1) and 10(a)(3).

The open session will be accessible via teleconference to 20 participants on a first come, first serve basis. To join the conference, submit inquiries to Ms. Yvette Springer at *Yvette.Springer@bis.doc.gov* no later than February 28, 2012.

A limited number of seats will be available for the public session. Reservations are not accepted. To the extent that time permits, members of the public may present oral statements to the Committee. The public may submit written statements at any time before or after the meeting. However, to facilitate the distribution of public presentation materials to the Committee members, the Committee suggests that presenters forward the public presentation materials prior to the meeting to Ms. Springer via email.

The Assistant Secretary for Administration, with the concurrence of the delegate of the General Counsel, formally determined on January 11, 2012, pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. app. 2 § (10)(d)), that the portion of the meeting dealing with pre-decisional changes to the Commerce Control List and U.S. export control policies shall be exempt from the provisions relating to public meetings found in 5 U.S.C. app. 2 §§ 10(a)(1) and 10(a)(3). The remaining portions of the meeting will be open to the public.

For more information, call Yvette Springer at (202) 482–2813.

Dated: February 13, 2012.

Yvette Springer,

Committee Liaison Officer.

[FR Doc. 2012–3685 Filed 2–15–12; 8:45 am]

BILLING CODE 3510–JT–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–835]

Furfuryl Alcohol From the People's Republic of China: Notice of Continuation of Antidumping Duty Order

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: As a result of the determination by the Department of Commerce (''the Department'') and the International Trade Commission (''ITC'') that revocation of the antidumping duty order on furfuryl alcohol from the People's Republic of China (''PRC'') would be likely to lead to continuation or recurrence of dumping and of material injury to an industry in the United States within a reasonably foreseeable time, the Department is publishing notice of the continuation of the antidumping duty order.

DATES: *Effective Date:* February 16, 2012.

FOR FURTHER INFORMATION CONTACT: Jennifer Moats, AD/CVD Operations, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington, DC 20230; telephone: (202) 482–5047.

SUPPLEMENTARY INFORMATION: On September 1, 2011, the Department initiated a sunset review of the antidumping duty order on furfuryl alcohol from the PRC pursuant to section 751(c) of the Tariff Act of 1930, as amended (''the Act'').[1]

The Department conducted an expedited sunset review of this order. As a result of its review, the Department found that revocation of the antidumping duty order would be likely to lead to continuation or recurrence of dumping and notified the ITC of the magnitude of the margins likely to prevail were the order to be revoked.[2]

On February 6, 2012, the ITC published its determination pursuant to section 751(c) of the Act that revocation of the antidumping duty order on furfuryl alcohol from the PRC would be likely to lead to continuation or recurrence of material injury to an industry in the United States within a reasonably foreseeable time.[3]

Scope of the Order

The merchandise covered by the order is furfuryl alcohol ($C_4H_3OCH_2OH$). Furfuryl alcohol is a primary alcohol, and is colorless or pale yellow in appearance. It is used in the manufacture of resins and as a wetting agent and solvent for coating resins, nitrocellulose, cellulose acetate, and other soluble dyes.

The product subject to the order is classifiable under subheading 2932.13.00 of the Harmonized Tariff Schedule of the United States (''HTSUS''). Although the HTSUS subheading is provided for convenience and customs purposes, our written description of the scope of this proceeding is dispositive.

Continuation of the Order

As a result of the determinations by the Department and the ITC that revocation of the antidumping duty order would be likely to lead to continuation or recurrence of dumping and material injury to an industry in the United States, pursuant to section 751(d)(2) of the Act, the Department hereby orders the continuation of the antidumping duty order on furfuryl alcohol from the PRC.

U.S. Customs and Border Protection will continue to collect antidumping duty cash deposits at the rates in effect at the time of entry for all imports of subject merchandise.

The effective date of continuation of this order will be the date of publication in the **Federal Register** of this Notice of Continuation. Pursuant to section 751(c)(2) of the Act, the Department intends to initiate the next five-year review of the order not later than February 2017.

This five-year (sunset) review and this notice are in accordance with sections 751(c) and 777(i)(1) of the Act and 19 CFR 351.218(f)(4).

Dated: February 7, 2012.

Paul Piquado,

Assistant Secretary for Import Administration.

[FR Doc. 2012–3715 Filed 2–15–12; 8:45 am]

BILLING CODE 3510–DS–P

[1] *See Initiation of Five-Year (''Sunset'') Review,* 76 FR 54430 (September 1, 2011); *see also Notice of Antidumping Duty Order: Furfuryl Alcohol From the People's Republic of China (PRC),* 60 FR 32302 (June 21, 1995).

[2] *See Furfuryl Alcohol From the People's Republic of China: Final Results of Expedited Third Sunset Review of the Antidumping Duty Order,* 76 FR 78613 (December 19, 2011).

[3] *See Furfuryl Alcohol From China,* 77 FR 5844 (February 6, 2012).

DEPARTMENT OF COMMERCE

International Trade Administration

[A–580–867]

Large Power Transformers From the Republic of Korea: Preliminary Determination of Sales at Less Than Fair Value and Postponement of Final Determination

AGENCY: Import Administration, International Trade Administration, Department of Commerce.

DATES: Effective Date: February 16, 2012.

SUMMARY: The Department of Commerce (the Department) preliminarily determines that large power transformers from the Republic of Korea (Korea) are being, or are likely to be, sold in the United States at less than fair value, as provided in section 733(b) of the Tariff Act of 1930, as amended (the Act). The estimated dumping margins are listed in the ''Suspension of Liquidation'' section of this notice. Interested parties are invited to comment on this preliminary determination. Pursuant to requests from interested parties, we are postponing for 60 days the final determination and extending provisional measures from a four-month period to not more than six months. Accordingly, we will make our final determination not later than 135 days after publication of the preliminary determination.

FOR FURTHER INFORMATION CONTACT: David Cordell or Brian Davis, AD/CVD Operations, Office 7, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington, DC 20230; telephone: (202) 482–0408 or (202) 482–7924, respectively.

SUPPLEMENTARY INFORMATION:

Background

On August 10, 2011, the Department initiated the antidumping duty investigation on large power transformers from Korea.[1] Petitioners in this investigation are ABB Inc., Delta Star, Inc., and Pennsylvania Transformer Technology Inc. (collectively, petitioners). The Department set aside a period of time for parties to raise issues regarding product coverage and invited all parties to submit comments within 20 calendar days of publication of the *Initiation Notice.*[2] The Department also set aside a time for parties to comment on product characteristics for use in the antidumping duty questionnaire.[3] Since the *Initiation Notice,* the following events have occurred.

On August 10, 2011, the Department notified all interested parties of its intent to select mandatory respondents for this investigation based on U.S. import data obtained from U.S. Customs and Border Protection (CBP) and set aside a period of time for parties to comment on the potential respondent selection. Parties were invited to submit comments within five calendar days from the date of that memorandum.[4]

On August 29, 2011, and August 30, 2011, Department officials visited Canonsburg, Pennsylvania to meet with officials of Pennsylvania Transformer Technology Inc., a petitioner in this proceeding, and their legal counsel, and also toured their facility.[5]

[1] *See Large Power Transformers from the Republic of Korea: Initiation of Antidumping Duty Investigation,* 76 FR 49439 (August 10, 2011) (*Initiation Notice*).

[2] *See Initiation Notice,* 76 FR at 49440; *see also Antidumping Duties; Countervailing Duties, Final Rule,* 62 FR 27296, 27323 (May 19, 1997) (*Preamble*).

[3] *See Initiation Notice,* 76 FR at 49440; *see also Preamble,* 62 FR at 27323.

[4] *See* Memorandum from Angelica Mendoza, Program Manager, to All Interested Parties, dated August 10, 2011.

[5] *See* Memorandum to the File, ''Antidumping Duty Investigation of Large Power Transformers from the Republic of Korea: Department Visit to

On September 2, 2011, the United States International Trade Commission (USITC) published its affirmative preliminary determination that there is a reasonable indication that an industry in the United States is materially injured or threatened with material injury, by reason of imports from Korea of large power transformers.[6]

On September 16, 2011, we selected Hyundai Heavy Industries Co., Ltd. (Hyundai) and Hyosung Corporation (Hyosung) as the mandatory respondents in this investigation and issued the Department's antidumping duty questionnaire to both respondents on September 28, 2011.[7]

Hyundai and Hyosung submitted responses to section A of the Department's antidumping duty questionnaire on November 2, 2011 and on November 16, 2011, both respondents submitted their responses to sections B (*i.e.,* the section covering comparison market sales) and C (*i.e.,* the section covering U.S. sales) of the Department's antidumping duty questionnaire. Also on November 16, 2011, Hyosung voluntarily reported a response to section D of the questionnaire (*i.e.,* the section covering the cost of production (COP) and constructed value (CV)).

On November 23, 2011, petitioners made a timely request pursuant to section 733(c)(1)(A) of the Act and 19 CFR 351.205(e) for a 50-day postponement of the preliminary determination and on December 6, 2011, the Department postponed the preliminary determination of this investigation until February 9, 2011.[8]

Hyosung

On November 30, 2011, the Department received an allegation from petitioners that home market sales made by Hyosung were made at prices below the cost of production and on December 9, 2011, the Department initiated a sales-below-cost of production investigation with respect to Hyosung.[9]

On November 21, 2011, the Department issued a supplemental questionnaire concerning Hyosung's section A–C responses. On December 12, and 19, 2011, Hyosung submitted its response to this supplemental questionnaire. On December 14, 2011, the Department issued a supplemental questionnaire regarding Hyosung's section D response.

On December 29, 2011, the Department issued a second supplemental questionnaire covering Hyosung's section A–C and supplemental responses. On January 6, 2012, we received the supplemental cost (*i.e.,* section D) response from Hyosung and on January 19, 2012, we received Hyosung's response to our December 29, 2011, supplemental questionnaire. On January 6, 2012, we issued a third sales supplemental questionnaire and on January 20, 2012, Hyosung submitted its response to this supplemental questionnaire. On February 2, 2012, we requested that Hyosung provide an updated U.S. sales database which includes actual shipment dates for all sales that have been shipped regardless of whether or not they have been invoiced, and on February 3, 2012, Hyosung submitted this revised U.S. sales database. Also on February 3, 2012, we requested that Hyosung provide an updated home market sales database which includes actual shipment dates for all sales that have been shipped regardless of whether they have been invoiced and on February 6, 2012, Hyosung submitted this revised home market sales database.

Hyundai

On November 21, 2011, the Department issued a supplemental questionnaire concerning Hyundai's section A–C responses. On December 12, 2011, Hyundai responded to this questionnaire. Also on December 12, 2011, Hyundai filed its response to the constructed value sections of the section D questionnaire.

On December 23, 2011, the Department issued a supplemental questionnaire to Hyundai covering Hyundai's section B–D responses. Hyundai responded to this supplemental questionnaire on January 13, and 18, 2012. On January 9, 2012, the Department issued a third sales supplemental questionnaire as well as a second supplemental cost questionnaire to which Hyundai responded on January 23, 2012.

On December 30, 2011, the Department received an allegation from petitioners that home market sales made by Hyundai were made at prices below the cost of production and on February 9, 2012, the Department decided not to initiate a sales-below-cost of production investigation.[10]

Deadline for Submission of Updated Information

With regard to cost estimates provided by respondents thus far, the Department will accept updated information for actual costs through and including December 31, 2011, where available. Further, with regard to estimates in the sales database, the Department will accept the corresponding actual sales information only through December 31, 2011. The Department does not expect to request updated information on sales or cost estimates for dates subsequent to December 31, 2011.

Period of Investigation

The period of investigation (POI) is July 1, 2010, to June 30, 2011. This period corresponds to the four most recent fiscal quarters prior to the month of the filing of the petition. *See* 19 CFR 351.204(b)(1).

Scope of Investigation

The scope of this investigation covers large liquid dielectric power transformers (LPTs) having a top power handling capacity greater than or equal to 60,000 kilovolt amperes (60 megavolt amperes), whether assembled or unassembled, complete or incomplete.

Incomplete LPTs are subassemblies consisting of the active part and any other parts attached to, imported with or invoiced with the active parts of LPTs. The ''active part'' of the transformer consists of one or more of the following when attached to or otherwise assembled with one another: The steel core or shell, the windings, electrical insulation between the windings, the mechanical frame for an LPT.

The product definition encompasses all such LPTs regardless of name designation, including but not limited to step-up transformers, step-down transformers, autotransformers, interconnection transformers, voltage regulator transformers, rectifier transformers, and power rectifier transformers.

The LPTs subject to this investigation are currently classifiable under subheadings 8504.23.0040,

Pennsylvania Transformer Technology Inc.,'' dated September 1, 2011.

[6] *See* 76 FR 54790 (September 2, 2011); *see also* USITC Publication 4526 (September 2011), titled ''Large Power Transformers from Korea: Investigation No. 731–TA–1189 (Preliminary).''

[7] *See* Memorandum to Christian Marsh, Deputy Assistant Secretary, from Richard O. Weible, Director, Office 7, titled ''Antidumping Duty Investigation of Large Power Transformers from the Republic of Korea (''Korea''): Respondent Selection Memorandum,'' dated September 16, 2011.

[8] *See Large Power Transformers from the Republic of Korea: Postponement of Preliminary Determination of Antidumping Duty Investigation,* 76 FR 76146 (December 6, 2011).

[9] *See* Memorandum to Richard O. Weible, Director, Office 7, titled, ''Petitioners' Allegation of Sales Below the Cost of Production for Hyosung Corporation,'' from the Team (Hyosung Cost Initiation Memo), dated December 9, 2011.

[10] *See* Memorandum to the File titled, ''Petitioners' Allegation of Sales Below the Cost of Production for Hyundai Heavy Industry Co., Ltd.,'' from the Team to Richard Weible dated February 8, 2012, (Hyundai Sales Below Cost Allegation Memorandum).

8504.23.0080 and 8504.90.9540 of the Harmonized Tariff Schedule of the United States (HTSUS). Although the HTSUS subheadings are provided for convenience and customs purposes, the written description of the scope of this investigation is dispositive.

Scope Comments

In accordance with the preamble to the Department's regulations, *see Preamble,* 62 FR at 27323, in our *Initiation Notice* we set aside a period of time for parties to raise issues regarding product coverage, and invited all parties to submit comments within 20 calendar days of publication of the *Initiation Notice.*

On August 23, 2011, we received comments from Hyundai and Hyosung concerning the scope of this investigation. In their submissions, both Hyundai and Hyosung request that the scope language be modified expressly to exclude spare parts when imported individually, or when imported with a complete LPT (whether assembled or unassembled) or with a subassembly, because they are not integral to the start-up or operation of an LPT.

On September 2, 2011, petitioners filed rebuttal comments regarding the scope comments by Hyundai and Hyosung. In their rebuttal comments, petitioners state that Hyundai and Hyosung failed to demonstrate the necessity for any exclusionary language and that the scope language published in the Department's *Initiation Notice* is clear and does not require modification. Petitioners state that the scope correctly does not exclude spare parts as this exclusion could be used to evade or circumvent any antidumping duty order that may be in place.

We preliminarily find that the language of the scope of the order is clear and does not require amendment.

Product Comparisons

We have considered the comments that were submitted by the interested parties concerning product-comparison criteria. In accordance with section 771(16) of the Act, all products produced by the respondents covered by the description in the ''Scope of Investigation'' section, above, and sold in Korea during the period of investigation are considered to be foreign like product for purposes of determining appropriate product comparisons to U.S. sales. We have relied on the following 18 criteria to match U.S. sales of subject merchandise to comparison-market sales of the foreign like product: (1) Number of phases; (2) maximum MVA rating; (3) transformer technology; (4) high line voltage; (5) high voltage winding basic insulation level; (6) number of windings in transformer; (7) type of tap changer and percentage regulation; (8) low line voltage; (9) impedance at maximum MVA rating; (10) type of core steel; (11) type of transformer; (12) low voltage winding basic insulation level; (13) load loss at maximum MVA rating; (14) no-load loss; (15) cooling class designation; (16) overload requirement; (17) decibel rating; and (18) frequency. We compared U.S. sales to sales of the next most similar foreign like product on the basis of the characteristics listed above, which were made in the ordinary course of trade. Where we were unable to find a home market match of such or similar merchandise, in accordance with section 773(a)(4) of the Act, we based NV on CV. Where appropriate, we made adjustments to CV in accordance with section 773(a)(8) of the Act.

Date of Sale

19 CFR 351.401(i) states that, in identifying the date of sale of the merchandise under consideration or foreign like product, the Secretary normally will use the date of invoice, as recorded in the exporter or producer's records kept in the ordinary course of business. Additionally, the Secretary may use a date other than the date of invoice if the Secretary is satisfied that a different date better reflects the date on which the exporter or producer establishes the material terms of sale.[11] The Department has explained that, ''in situations involving large custom-made merchandise in which the parties engage in formal negotiation and contracting procedures, the Department usually will use a date other than the date of invoice.'' *Preamble,* 62 FR at 27349. The Court of International Trade (''CIT'') has stated that ''a party seeking to establish a date of sale other than invoice date bears the burden of producing sufficient evidence to 'satisfy' the Department that a different date better reflects the date on which the exporter or producer establishes the material terms of sale.'' [12] Alternatively, the Department may exercise its discretion to rely on a date other than invoice date if the Department ''provides a rational explanation as to why the alternative date 'better reflects' the date when 'material terms' are established.'' [13] The date of sale is generally the date on which the parties establish the material terms of the sale. This normally includes the price, quantity, delivery terms and payment terms.[14]

In this case, Hyosung argued that the date of sale should be the purchase order date. *See* Hyosung's letter to the Department dated October 11, 2011. Hyosung also asked the Department to modify its reporting period to ''permit Hyosung to report all U.S. sales that were invoiced during the POI (*i.e.,* between July 1, 2010 and June 30, 2011), even if the purchase order date falls before July 1, 2010.'' Hyundai filed a similar request on October 12, 2011. Petitioners initially urged the Department to have respondents report all sales based upon purchase order date and noted that Hyosung concedes that ''sales terms do not change after the purchase order is issued,'' and that ''the purchase order date satisfies the Department's definition of the date of sales because purchase orders nearly always memorialize all material terms,'' quoting Hyosung's October 11, 2011, letter at 3. Petitioners concluded that ''thus, the date of the purchase order, not the invoice date, is the proper date of sale in this proceeding.'' *See* Petitioners letter dated October 14, 2011, at 3. The Department issued a letter to all parties on October 17, 2011, noting that ''no party to this proceeding has placed any information on the record to call in to question the fact that purchase order date satisfies the Department's definition of the date of sale,'' and that ''based upon what is currently on the record, it appears that material terms of sale for sales of large power transformers are established at the purchase order date.'' *See* Letter to all interested parties from the Department entitled ''Antidumping Duty Investigation of Large Power Transformers from the Republic of Korea (''Korea''): Request for Modified Reporting Period'' dated October 17, 2011.

Since that time, petitioners have raised concerns about the reported date of sale, arguing that we should ''rely on the *earliest* document in the sales process that establishes the essential elements of a sale'' and that in this case this ''is either the date of the alliance (or other relevant descriptor, *e.g.,* 'blanket,' 'long-term,' etc.) contract, the date on which the customer transmits a blanket purchase order to Hyundai or Hyosung, or the date on which the customer transmits its production order forecast to the respondents.'' *See* Petitioners letter to the Department dated January

[11] *See* 19 CFR 351.401(i); *see also Allied Tube & Conduit Corp.* v. *United States,* 132 F. Supp. 2d 1087, 1090 (CIT 2001) (quoting 19 CFR 351.401(i)) (''*Allied Tube''*).

[12] *See Allied Tube,* 132 F. Supp. 2d at 1090–1092.

[13] *SeAH Steel Corp.* v. *United States,* 25 C.I.T. 133, 135 (Ct. Int'l Trade 2001).

[14] *See USEC Inc.* v. *United States,* 31 C.I.T. 1049, 1055 (Ct. Int'l Trade 2007).

20, 2012, at 2. Petitioners claim ''the respondents have withheld complete documentation that would allow Commerce to establish accurately the date of sale,'' and that ''Commerce should find that record evidence indicates that the correct date of sale is established at a point earlier in the sales transaction process than the 'purchase order' date identified by respondents.'' *Id.* at 23–24.

For the purposes of this preliminary determination, we are using the purchase order date as the date of sale because record evidence currently demonstrates that this date best reflects the date upon which the material terms of sale were established. However, we are excluding from our analysis those sales which are known to be based on long term contracts executed prior to the POI because it is unclear whether the material terms of these sales were set during the POI. We will further examine whether there is other information that denotes a more appropriate date of sale as it is unclear from the record whether the material terms of these sales were set prior to the POI. We intend to issue one final supplemental questionnaire to each respondent regarding the date of sale issue.

Fair Value Comparisons

To determine whether respondents' sales of large power transformers from Korea to the United States were made at LTFV, we compared the constructed export price (CEP) to normal value (NV) or constructed value, as appropriate and as described in the ''Constructed Export Price'' and ''Normal Value'' sections of this notice. In accordance with section 777A(d)(1)(A)(i) of the Act, we compared POI weighted-average CEPs to POI weighted-average NVs or constructed values, as appropriate.

Constructed Export Price

For the price to the United States, we used CEP, in accordance with section 772(b) of the Act. We calculated CEP for those sales where a person in the United States, affiliated with the foreign exporter or acting for the account of the exporter, made the sale to the first unaffiliated purchaser in the United States of the subject merchandise. *See* section 772(b) of the Act. We based CEP on the packed prices charged to the first unaffiliated customer in the United States and the applicable terms of sale.

In accordance with section 772(b) of the Act, we calculated CEP where the record established that sales made by Hyundai and Hyosung were made in the United States after the date of importation by or for the account of the producer or exporter, or by a seller affiliated with the producer or exporter, to a purchaser not affiliated with the producer or exporter.

Hyundai

In accordance with section 772(c)(2)(A) of the Act, and where appropriate, we made deductions from the starting price for certain billing adjustments, early payment discounts, quantity discounts, and certain other discounts, including rebates. We also made further deductions to price for certain movement expenses where appropriate, for foreign inland freight, inland insurance, foreign brokerage, U.S. inland freight, certain other transportation expenses, U.S. customs duties and U.S. brokerage and handling expenses, pursuant to section 772(c)(2)(A) of the Act.

Pursuant to section 772(d)(1) of the Act, we made additional adjustments to CEP for commissions, credit expenses, bank charges, direct selling expenses associated with costs incurred in the United States, and other indirect selling expenses in the United States associated with economic activity in the United States. Pursuant to section 772(d)(3) of the Act, we made an adjustment for CEP profit. For a detailed discussion of these adjustments, *see* Memorandum to the file, through Angelica Mendoza, Program Manager, from David Cordell and Brian Davis, International Trade Analysts, titled ''Analysis Memorandum for the Preliminary Determination of the Antidumping Duty Investigation of Large Power Transformers from the Republic of Korea: Hyundai Heavy Industries Co., Ltd.,'' dated February 9, 2012 (Hyundai Preliminary Analysis Memorandum).

Hyosung

In accordance with section 772(c)(2)(A) of the Act, and where appropriate, we made deductions from the starting price for certain movement expenses, foreign inland freight, foreign brokerage, foreign inland insurance, U.S. inland freight, international freight, marine insurance, and U.S. brokerage and handling expenses, pursuant to section 772(c)(2)(A) of the Act. Pursuant to section 772(d)(1) of the Act, we made additional adjustments to CEP for commissions, credit expenses, warranty expenses, inventory carrying costs incurred in Korea, direct selling expenses associated with costs incurred in the United States (*i.e.,* oil and installation expenses), and indirect selling expenses. Pursuant to section 772(d)(3) of the Act, we made an adjustment for CEP profit. For a detailed discussion of these adjustments, *see* Memorandum to the file, through Angelica Mendoza, Program Manager, from David Cordell and Brian Davis, International Trade Analysts, titled ''Analysis Memorandum for the Preliminary Determination of the Antidumping Duty Investigation of Large Power Transformers from the Republic of Korea: Hyosung Corporation,'' dated February 9, 2012 (Hyosung Preliminary Analysis Memorandum).

Normal Value

A. Home Market Viability and Comparison-Market Selection

To determine whether there is a sufficient volume of sales in the home market to serve as a viable basis for calculating NV (*i.e.,* the aggregate volume of home market sales of the foreign like product is equal to or greater than five percent of the aggregate volume of U.S. sales), we compared respondents' volume of home market sales of the foreign like product to its volume of U.S. sales of the subject merchandise. *See* section 773(a)(1)(C) of the Act. Based on this comparison, we determined that both respondents had a viable home market during the POI. Consequently, we based NV on home market sales. Although Hyundai has argued that we should base NV on CV, based on the record of the case, the Department is following its normal methodology and invites parties to comment on the matches under a price-to-price comparison in their briefs.

B. Affiliated Party Transactions and Arm's-Length Test

Pursuant to its regulations, the Department may use prices from sales made to affiliated parties if the price is comparable to the price at which the exporter or producer sold the foreign like product to a non-affiliate. *See* 19 CFR 351.403(c). During the POI, Hyundai sold foreign like product to an affiliated customer for its own use and not for resale. To test whether the sales made by Hyundai were made at arm's-length prices, and thus comparable to the prices for non-affiliates, we compared, on a product-specific basis, the starting prices of sales to affiliated and unaffiliated customers, net of all applicable billing adjustments, discounts and rebates, movement charges, direct selling expenses and packing expenses. Where the price to the affiliated party was, on average, within a range of 98 to 102 percent of the price of the same or comparable merchandise sold to unaffiliated parties, we determined that sales made to the affiliated party were at arm's-length. *See* 19 CFR 351.403(c); *see also Stainless*

Steel Sheet and Strip in Coils From Japan: Preliminary Results of Antidumping Duty Administrative Review, 74 FR 39615 (August 7, 2009), unchanged in *Stainless Steel Sheet and Strip in Coils From Japan: Final Results of Antidumping Duty Administrative Review,* 75 FR 6631 (February 10, 2010). Sales to affiliated customers in the home market that were not made at arm's-length prices were excluded from our analysis because we considered them to be outside the ordinary course of trade and thus not appropriate for determining normal value. *See* section 771(15) of the Act and 19 CFR 351.102(b)(35).

C. Level of Trade

In accordance with section 773(a)(1)(B) of the Act, to the extent practicable, we determine NV based on sales in the comparison market at the same level of trade (LOT) as the export price or CEP. *See also* section 773(a)(7) of the Act. Pursuant to 19 CFR 351.412(c)(1)(iii), the NV LOT is based on the starting price of the sales in the comparison market or, when NV is based on constructed value, the starting price of the sales from which we derive selling, general and administrative expenses, and profit. For CEP sales (which constituted all sales by both Hyundai and Hyosung), the U.S. LOT is based on the starting price of the U.S. sales, as adjusted under section 772(d) of the Act, which is from the exporter to the importer. *See* 19 CFR 351.412(c)(1)(ii).

To determine whether NV sales are at a different LOT than CEP sales, we examine stages in the marketing process and selling functions along the chain of distribution between the producer and the unaffiliated customer. *See* 19 CFR 351.412(c)(2). If the comparison-market sales are at a different LOT, and the difference affects price comparability, as manifested in a pattern of consistent price differences between the sales on which NV is based and comparison-market sales at the LOT of the export transaction, we make an LOT adjustment under section 773(a)(7)(A) of the Act. For CEP sales, if the NV level is more remote from the factory than the CEP level and there is no basis for determining whether the difference in levels between NV and CEP affects price comparability, we adjust NV under section 773(a)(7)(B) of the Act (the CEP-offset provision). *See Notice of Final Determination of Sales at Less Than Fair Value: Certain Cut-to-Length Carbon Steel Plate from South Africa,* 62 FR 61731, 61732–33 (November 19, 1997) (applying the CEP offset analysis under section 773(a)(7)(B)).

In this investigation, we obtained information from Hyundai and Hyosung regarding the marketing stages involved by both parties making their reported home market and U.S. market sales, including a description of the selling activities performed by the respondents and/or their affiliates for each channel of distribution. *See* Hyundai's AQR at pages A–16 through A–21 and Attachment A–12; *see also* Hyundai's TSQR dated January 23, 2012, at pages 1 through 2 and Exhibit 1 (selling activities chart); and Hyosung's AQR at pages A–17 through A–18; *see also* Hyosung's SQR at pages SA–11 through SA–17 and Exhibit SA–6 (selling activities chart). We did not make an LOT adjustment under section 773(a)(7)(A) of the Act and 19 CFR 351.412(e) because there was only one home market LOT for each respondent and we were unable to identify a pattern of consistent price differences attributable to differences in LOTs. *See* 19 CFR 351.412(d). Under section 773(a)(7)(B) of the Act and 19 CFR 351.412(f), we are preliminarily granting a CEP offset to reduce normal value by the appropriate amount of indirect selling expenses for both Hyundai and Hyosung because the NV sales for each company are at a more advanced LOT than the LOT for their U.S. CEP sales.

For a detailed description of our LOT methodology and a summary of the company-specific LOT findings for this preliminary determination, *see* Hyundai Preliminary Analysis Memorandum and Hyosung Preliminary Analysis Memorandum.

D. Cost of Production Analysis

Based on the Department's analysis of the Petitioners' allegation, we initiated a sales-below-cost investigation to determine whether Hyosung had sales that were made at prices below their COP pursuant to section 773(b) of the Act. *See* Hyosung Cost Initiation Memo. As stated in the ''Background'' section of this notice, above, we declined to initiate such an investigation for Hyundai. *See* Hyundai Sales Below Cost Allegation Memorandum.

1. Calculation of Cost of Production

We calculated the COP based on the sum of the cost of materials and fabrication for the foreign like product, plus amounts for selling, general, and administrative (SG&A) expenses and packing, in accordance with section 773(b)(3) of the Act. We relied on the COP data submitted by respondents except where noted below. Based on the review of record evidence, respondents did not appear to experience significant changes in the cost of manufacturing during the period of investigation. Therefore, we followed our normal methodology of calculating an annual weighted-average cost.

Hyosung

We reclassified certain selling, G&A and other non-operating income and expense items that appeared not to be properly classified by Hyosung and revised Hyosung's calculation of the G&A expense ratio. For additional details, *see* Memorandum to Neal M. Halper from Sheikh M. Hannan titled ''Cost of Production and Constructed Value Calculation Adjustments for the Preliminary Determination—Hyosung Corporation'' dated February 9, 2012 (Hyosung Preliminary Cost Calculation Memorandum).

Hyundai

We excluded unconsolidated foreign exchange gains and losses from Hyundai's G&A expenses and included the corresponding consolidated gains and losses in the calculation of the financial expense ratio according to our normal practice. We disallowed the offset to Hyundai's G&A expense for certain miscellaneous income items. For additional details, *see* Memorandum to Neal M. Halper from Ernest Z. Gziryan titled ''Cost of Production and Constructed Value Calculation Adjustments for the Preliminary Determination—Hyundai Heavy Industries Co., Ltd. and Hyundai Corporation, USA'' dated February 9, 2012 (Hyundai Preliminary Cost Calculation Memorandum).

2. Test of Comparison Market Prices

With respect to Hyosung, on a product-specific basis, pursuant to section 773(a)(1)(B)(i) of the Act, we compared the adjusted weighted-average COP to the home market sales prices of the foreign like product, in order to determine whether the sale prices were below the COP. For purposes of this comparison, we used COP exclusive of selling and packing expenses. The prices were net of billing adjustments, movement charges, discounts, direct and indirect selling expenses and packing expenses, where appropriate. *See* Hyosung Preliminary Analysis Memorandum.

3. Results of COP Test

Section 773(b)(1) provides that where sales made at less than the COP ''have been made within an extended period of time in substantial quantities'' and ''were not at prices which permit recovery of all costs within a reasonable period of time'' the Department may disregard such sales when calculating

NV. Pursuant to section 773(b)(2)(C)(i) of the Act, we did not disregard below-cost sales that were not made in ''substantial quantities,'' *i.e.,* where less than 20 percent of sales of a given product were at prices less than the COP. We disregarded below-cost sales when they were made in substantial quantities, *i.e.,* where 20 percent or more of a respondent's sales of a given product were at prices less than the COP and where ''the weighted average per unit price of the sales * * * is less than the weighted average per unit cost of production for such sales.'' *See* section 773(b)(2)(C)(ii) of the Act. Finally, based on our comparison of prices to the weighted-average COPs for the POR, we considered whether the prices would permit the recovery of all costs within a reasonable period of time. *See* section 773(b)(2)(D) of the Act.

Therefore, for Hyosung, we disregarded below-cost sales of a given product of 20 percent or more and used the remaining sales as the basis for determining NV, in accordance with section 773(b)(1) of the Act. *See* Hyosung Preliminary Analysis Memorandum.

E. Calculation of Normal Value Based on Comparison-Market Prices

We calculated NV for Hyundai and Hyosung based on the reported packed, ex-factory or delivered prices to comparison market customers. We made deductions from the starting price, where appropriate, for billing adjustments, early payment and certain other discounts, other revenues received, inland freight and insurance, and warehousing expenses, pursuant to section 773(a)(6)(B)(ii) of the Act.

Pursuant to section 773(a)(6)(C)(iii) of the Act and 19 CFR 351.410(b), we made, where appropriate, circumstance-of-sale adjustments (*i.e.,* bank charges for Hyosung). We added U.S. packing costs and deducted home market packing costs, in accordance with sections 773(a)(6)(A) and (B)(i) of the Act. Finally, we made a CEP offset pursuant to section 773(a)(7)(B) of the Act and 19 CFR 351.412(f). We calculated the CEP offset as the lesser of the indirect selling expenses incurred on the home market sales or the indirect selling expenses deducted from the starting price in calculating CEP.

When comparing U.S. sales with comparison market sales of similar, but not identical, merchandise, we also made adjustments for physical differences in the merchandise in accordance with section 773(a)(6)(C)(ii) of the Act and 19 CFR 351.411. We based this adjustment on the difference in the variable cost of manufacturing for the foreign-like product and subject merchandise. *See* 19 CFR 351.411(b).

F. Price-to-CV Comparison

Where we were unable to find a home market match of such or similar merchandise, in accordance with section 773(a)(4) of the Act, we based NV on CV. Where appropriate, we made adjustments to CV in accordance with section 773(a)(8) of the Act.

G. Constructed Value

In accordance with section 773(e) of the Act, we calculated CV based on the sum of Hyundai's and Hyosung's respective material and fabrication costs, SG&A expenses, profit, and U.S. packing costs. We calculated the COP component of CV as described above in the ''Cost of Production Analysis'' section of this notice. In accordance with section 773(e)(2)(A) of the Act, we based SG&A expenses and profit on the amounts incurred and realized by the respondents in connection with the production and sale of the foreign like product in the ordinary course of trade, for consumption in the foreign country.

Currency Conversion

We made currency conversions into U.S. dollars in accordance with section 773A(a) of the Act and 19 CFR 351.415(a) based on the exchange rates in effect on the dates of the U.S. sales as certified by the Federal Reserve Bank.

Verification

As provided in section 782(i)(1) of the Act, we intend to verify the information relied upon in making our final determination for Hyundai and Hyosung.

Preliminary Determination

The weighted-average dumping margins are as follows:

Manufacturer/ Exporter	Weighted-average margin (percent)
Hyundai Heavy Industries Co., Ltd.	21.79
Hyosung Corporation	38.07
All-others	29.93

Suspension of Liquidation

In accordance with section 733(d)(2) of the Act, we will direct CBP to suspend liquidation of all entries of large power transformers from Korea that are entered, or withdrawn from warehouse, for consumption on or after the date of publication of this notice in the **Federal Register**. We will also instruct CBP to require a cash deposit or the posting of a bond equal to the weighted-average dumping margins, as indicated in the chart below. These suspension of liquidation instructions will remain in effect until further notice.

All Others Rate

Section 735(c)(5)(A) of the Act provides that the estimated ''All Others'' rate shall be an amount equal to the weighted average of the estimated weighted-average dumping margins established for exporters and producers individually investigated, excluding any zero or *de minimis* margins, and any margins determined entirely under section 776 of the Act. Hyundai and Hyosung are the only respondents in this investigation for which the Department has calculated a company-specific rate that is not zero or *de minimis.* Therefore, for purposes of determining the ''all others'' rate and pursuant to section 735(c)(5)(A) of the Act, we are using the simple average of the dumping margins calculated for Hyundai and Hyosung for the ''all others'' rate, as referenced in the ''Suspension of Liquidation'' section, above. *See Seamless Refined Copper Pipe and Tube From Mexico: Final Determination of Sales at Less Than Fair Value,* 75 FR 60723, 60724 (October 1, 2010) (using a simple average to determine the ''All Others'' rate when there only two relevant weighted-average dumping margins because use of a weighted average risks disclosure of business proprietary information).[15]

Disclosure

The Department will disclose to parties the calculations performed in connection with this preliminary determination within five days of the date of publication of this notice. *See* 19 CFR 351.224(b).

Postponement of Final Determination and Extension of Provisional Measures

Section 735(a)(2) of the Act provides that a final determination may be postponed until not later than 135 days after the date of the publication of the preliminary determination if, in the event of an affirmative preliminary determination, a request for such postponement is made by exporters, who account for a significant proportion of exports of the subject merchandise, or in the event of a negative preliminary determination, a request for such postponement is made by the petitioner. The Department's regulations, at 19 CFR 351.210(e)(2), require that requests by

[15] While Hyosung provided ranged data of their quantities and values in its public version, Hyundai provided indexed data and thus the Department cannot disclose a weighted-average dumping margin for the all other's rate.

respondents for postponement of a final determination be accompanied by a request for extension of provisional measures from a four-month period to not more than six months.

On December 22, 2011, and January 5, 2012, Hyosung and Hyundai, respectively, requested that in the event of an affirmative preliminary determination in this investigation, the Department postpone its final determination by 60 days (135 days after publication of the preliminary determination) and extend the application of the provisional measures prescribed under section 733(d) of the Act and 19 CFR 351.210(e)(2), from a four-month period to a six-month period. In accordance with section 735(a)(2)(A) of the Act and 19 CFR 351.210(b)(2)(ii), because (1) our preliminary determination is affirmative; (2) the requesting producers/exporters account for a significant proportion of exports of the subject merchandise; and (3) no compelling reasons for denial exist, we are granting this request and are postponing the final determination until no later than 135 days after the publication of this notice in the **Federal Register**. Suspension of liquidation will be extended accordingly. We are also granting the request to extend the application of the provisional measures prescribed under section 733(d) of the Act and 19 CFR 351.210(e)(2) from a four-month period to a six-month period.

USITC Notification

In accordance with section 733(f) of the Act, we have notified the USITC of the Department's preliminary affirmative determination. If the Department's final determination is affirmative, the USITC will determine before the later of 120 days after the date of this preliminary determination or 45 days after our final determination whether imports of large power transformers from Korea are materially injuring, or threatening material injury to, the U.S. industry. *See* section 735(b)(2) of the Act. Because we are postponing the deadline for our final determination to 135 days from the date of the publication of this preliminary determination, the USITC will make its final determination no later than 45 days after our final determination.

Public Comment

Interested parties are invited to comment on the preliminary determination. Interested parties may submit case briefs to the Department no later than seven days after the date of the issuance of the last verification report in this proceeding. *See* 19 CFR 351.309(c)(1)(i). Rebuttal briefs, the content of which is limited to the issues raised in the case briefs, must be filed within five days from the deadline date for the submission of case briefs. *See* 19 CFR 351.309(d)(1) and 19 CFR 351.309(d)(2). A list of authorities used, a table of contents, and an executive summary of issues should accompany any briefs submitted to the Department. Executive summaries should be limited to five pages total, including footnotes. Interested parties, who wish to comment on the preliminary determination must file briefs electronically using Import Administration's Antidumping and Countervailing Duty Centralized Electronic Service System (''IA ACCESS''). An electronically filed document must be received successfully in its entirety by the Department's electronic records system, IA ACCESS, by 5 p.m. Eastern Standard Time.

In accordance with section 774(1) of the Act, the Department will hold a public hearing, if timely requested, to afford interested parties an opportunity to comment on arguments raised in case or rebuttal briefs, provided that such a hearing is requested by an interested party. *See also* 19 CFR 351.310. Interested parties, who wish to request a hearing, or to participate if one is requested, must submit a written request to the Assistant Secretary for Import Administration, U.S. Department of Commerce, filed electronically using IA ACCESS, as noted above. An electronically filed document must be received successfully in its entirety by the Department's electronic records system, IA ACCESS, by 5 p.m. Eastern Standard Time within 30 days after the date of publication of this notice. *See* 19 CFR 351.310(c). Requests should contain the party's name, address, and telephone number, the number of participants, and a list of the issues to be discussed. If a request for a hearing is made, we will inform parties of the scheduled date for the hearing which will be held at the U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington, DC 20230, at a time and location to be determined. *See* 19 CFR 351.310. Parties should confirm by telephone the date, time, and location of the hearing.

This determination is issued and published pursuant to sections 733(f) and 777(i)(1) of the Act.

Dated: February 9, 2012.

Paul Piquado,

Assistant Secretary for Import Administration.

[FR Doc. 2012–3716 Filed 2–15–12; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XB003

International Pacific Halibut Commission Appointments

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of nominations.

SUMMARY: NOAA is soliciting nominations for two individuals to serve as United States Commissioners to the International Pacific Halibut Commission (IPHC). This action is necessary to ensure that the interests of the United States and all of its stakeholders in the Pacific halibut fishery are adequately represented. The intended effect of this action is to improve transparency and stakeholder participation in the nomination process.

DATES: Nominations must be received by March 19, 2012.

ADDRESSES: Nominations for U.S. Commissioners to the IPHC should be made in writing to Mr. Patrick E. Moran, Office of International Affairs, National Marine Fisheries Service, at 1315 East-West Highway, Silver Spring, MD 20910. Nominations can also be sent via fax (301–713–2313) or email (*Pat.Moran@noaa.gov*).

FOR FURTHER INFORMATION CONTACT: Mr. Patrick E. Moran, (301) 427–8370.

SUPPLEMENTARY INFORMATION:

Background

The IPHC is a bilateral regional fishery management organization established pursuant to the Convention between Canada and the United States for the Preservation of the Halibut Fishery of the North Pacific Ocean and Bering Sea (Convention). The Convention was signed at Ottawa, Ontario, on March 2, 1953, and was amended by a Protocol Amending the Convention signed at Washington, DC, on March 29, 1979. The Convention's central objective is to develop the stocks of Pacific halibut in waters off the west coasts of Canada and the United States to levels that will permit the optimum yield from the Pacific halibut fishery and to maintain the stocks at those levels. The IPHC fulfills this objective in part by recommending Pacific halibut fishery conservation and management measures for approval by the United States and Canada. Pursuant to the Northern Pacific Halibut Act of 1982, the Secretary of State, with the concurrence of the Secretary of Commerce, may accept or reject, on behalf of the United States, conservation and management measures recommended by the IPHC. 16 U.S.C. 773b. Measures accepted by the Secretary of State are adopted as binding regulations governing fishing for Pacific halibut in Convention waters of the United States. 16 U.S.C. 773c(b)(1). More information on the IPHC can be found at *http://www.iphc.int.*

Section 773a of the Northern Pacific Halibut Act of 1982 (16 U.S.C. 773a) requires that the United States be represented on the IPHC by three U.S. Commissioners. U.S. Commissioners are appointed for a term not to exceed 2 years, but are eligible for reappointment. Of the Commissioners:

(1) One must be an official of the National Oceanic and Atmospheric Administration; and

(2) two must be knowledgeable or experienced concerning the Northern Pacific halibut fishery; of these, one must be a resident of Alaska and the other shall be a nonresident of Alaska. Of the three commissioners described in paragraphs (1) and (2), one must also be a voting member of the North Pacific Fishery Management Council.

(3) Commissioners who are not Federal employees are not considered to be Federal employees except for the purposes of injury compensation or tort claims liability as provided in section 8101 *et seq.* of title 5 and section 2671 *et seq.* of title 28.

In their official IPHC duties, Commissioners represent the interests of the United States and all of its stakeholders in the Pacific halibut fishery. These duties require a modest amount of travel (typically two or three trips per year lasting less than a week), and travel expenses are paid by the U.S. Department of State. Commissioners receive no compensation for their services.

Nomination Process

The U.S. Department of Commerce is currently accepting nominations for two U.S. Commissioners for the IPHC who are not officials of the National Oceanic and Atmospheric Administration (NOAA). Successful nominees will be considered for appointment by the President and (pending Presidential action) interim designation by the Department of State.

Nomination packages should provide details of an individual's knowledge and experience in the Pacific halibut fishery. Examples of such knowledge and/or experience could include (but are not limited to) such activities as: Participation in commercial, tribal, Community Development Quota (CDQ) and/or sport and charterboat halibut fishing operations; participation in halibut processing operations; and participation in Pacific halibut management activities.

Nomination packages should document an individual's qualifications and state of residence. Self-nominations are acceptable, and current and former IPHC Commissioners are eligible for reappointment. Résumés, curriculum vitae, and/or letters of recommendation are useful but not required. Nomination packages will be evaluated on a case-by-case basis by officials in the Department of Commerce who are familiar with the duties and responsibilities of IPHC Commissioners; evaluations will consider the aggregate of an individual's prior experience and knowledge of the Pacific halibut fishery, residency requirements, and any letters of recommendation provided. Nominees will be notified of their status (including rejection or approval) and any need for further information once the nomination process is complete.

Dated: February 10, 2012.

Rebecca Lent,

Director, Office of International Affairs, National Marine Fisheries Service.

[FR Doc. 2012–3697 Filed 2–15–12; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XB008

South Atlantic Fishery Management Council; Public Meetings

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of public meetings.

SUMMARY: The South Atlantic Fishery Management Council will hold meetings of its: Law Enforcement Advisory Panel; Ad Hoc Data Collection Committee; Law Enforcement Committee; Spiny Lobster Committee; Ecosystem-Based Management Committee; King and Spanish Mackerel Committee; Shrimp Committee; Information and Education Committee; Executive Finance Committee; Southeast Data, Assessment and Review (SEDAR) Committee; Golden Crab Committee; Catch Shares Committee; Snapper Grouper Committee; and a meeting of the Full Council. The Council will take action as necessary.

The Council will hold an informal public question and answer session regarding agenda items and a public comment session. See **SUPPLEMENTARY INFORMATION** for additional details.

DATES: The Council meeting will be held March 5–9, 2012. See **SUPPLEMENTARY INFORMATION** for specific dates and times.

ADDRESSES: The meeting will be held at the Savannah Hilton DeSoto, 15 East Liberty Street, Savannah, GA 31401; telephone: (1–877) 280–0751 or (912) 232–9000; fax: (912) 232–6018. Copies of documents are available from Kim Iverson, Public Information Officer, South Atlantic Fishery Management Council, 4055 Faber Place Drive, Suite 201, North Charleston, SC 29405.

FOR FURTHER INFORMATION CONTACT: Kim Iverson, Public Information Officer; telephone: (843) 571–4366 or toll free at (866) SAFMC–10; fax: (843) 769–4520; email: *kim.iverson@safmc.net.*

SUPPLEMENTARY INFORMATION:

Meeting Dates

1. Law Enforcement Advisory Panel Meeting: March 5, 2012, 1:30 p.m. Until 5 p.m.

The Law Enforcement Advisory Panel (AP) will receive an update on recent amendments and review and develop comments on the following amendments: Snapper Grouper Amendment 18B (golden tilefish); Snapper Grouper Regulatory Amendment 12 (framework action to adjust the golden tilefish Annual Catch Limit (ACL), Optimum Yield (OY) and Annual Catch Target (ACT) in the fishery); Comprehensive Ecosystem-Based Amendment 3; Snapper Grouper Amendment 20B (wreckfish Individual Transferable Quota (ITQ) program modifications); Spiny Lobster Amendment 11 (weather-related fishery closures and a revised Minimum Stock Size Threshold (MSST) for pink shrimp); and Golden Crab Amendment 6 (catch share program for the commercial fishery). The AP will also begin the process for the 2011 Law Enforcement Officer of the Year award.

Note: Concurrent Session.

2. Ad Hoc Data Collection Committee Meeting: March 5, 2012, 1:30 p.m. Until 5 p.m.

The Ad Hoc Data Collection Committee will discuss the joint South Atlantic/Gulf Council dealer permits and review commercial and for-hire vessel reporting requirements in the South Atlantic.

3. Law Enforcement Committee Meeting: March 6, 2012, 8:30 a.m. Until 9:30 a.m.

The Law Enforcement Committee will receive a report from the Law Enforcement AP and discuss other issues as appropriate.

4. Spiny Lobster Committee Meeting: March 6, 2012, 9:30 a.m. Until 10:30 a.m.

The Spiny Lobster Committee will receive an overview of Spiny Lobster Amendment 11, which includes measures to help protect threatened/endangered species. These measures include area closures for the commercial trap fishery to protect corals and gear marking requirements for trap lines. The Committee will also review public hearing comments and Supplemental Draft Environmental Impact Statement (SDEIS) comments and modify Amendment 11 as appropriate. The Committee will provide recommendations to Council.

5. Ecosystem-Based Management Committee Meeting: March 6, 2012, 10:30 a.m. Until 3 p.m.

The Ecosystem-Based Management Committee will receive updates on: The status of catches versus quota for octocorals; the status of Comprehensive Ecosystem-Based Amendment 2; the Florida Keys National Marine Sanctuary Strategic Plan; and public scoping comments for Comprehensive Ecosystem-Based Amendment 3 (CE–BA3). The Committee will develop recommendations for CE–BA3, give an update on ecosystem activities, and provide direction to staff.

6. King and Spanish Mackerel Committee Meeting: March 6, 2012, 3 p.m. Until 5 p.m.

The King and Spanish Mackerel Committee will receive updates on the status of catches versus quotas for species under quota management and the status of Mackerel Amendment 18, which establishes ACLs and Accountability Measures (AMs) for mackerel and cobia. The Committee will also receive a presentation on king mackerel tournament sales of fish and will select items to include in the joint South Atlantic and Gulf Mackerel Amendments 20 and 21. The Committee will provide guidance to staff and recommendations to Council.

7. Shrimp Committee Meeting: March 7, 2012, 8:30 a.m. Until 10 a.m.

The Shrimp Committee will review scoping comments for Shrimp Amendment 9, which would expedite the closure process during severe cold events in order to protect overwintering shrimp populations and would revise the MSST proxy for pink shrimp. The Committee will take action as appropriate and provide guidance to staff.

8. Information and Education Committee Meeting: March 7, 2012, 10 a.m. Until 11 a.m.

The Information and Education Committee will review the recommendations from the Snapper Grouper AP relating to outreach and will receive presentations on the use of social media tools. Additionally, the Committee will receive a review of the recent public hearing and scoping meetings and discuss options for future meetings. The Committee will provide recommendations as appropriate.

9. Executive Finance Committee Meeting: March 7, 2012, 11 a.m. Until 12 Noon

The Executive Finance Committee will: Receive a report on the Council Year (CY) 2012 Council expenditures; review and approve the draft CY2012 Council activities schedule and budget; and review the President's 2013 budget proposal.

10. SEDAR Committee Meeting: March 7, 2012, 1:30 p.m. Until 3:30 p.m.

The SEDAR Committee will receive an overview of SEDAR activities and review SEDAR assessment priorities. The Committee will also receive a presentation on the Marine Recreational Information Program (MRIP) Electronic Logbook Pilot Study, a report on recent MRIP workshops and a report on revised MRIP catch estimates. The Committee will discuss and develop recommendations for the next SEDAR Steering Committee meeting.

11. Golden Crab Committee Meeting: March 7, 2012, 3:30 p.m. Until 5:30 p.m.

The Golden Crab Committee will review: The status of commercial catches versus quotas (amount landed to date); public hearing comments on Golden Crab Amendment 6; Golden Crab AP recommendations; and staff modifications to the amendment. The Committee will provide direction to staff and recommendations to the Council for approving the amendment for Secretarial review and approval.

Note: There will be an informal public question and answer session with the NMFS Regional Administrator and the Council Chairman on March 7, 2012, beginning at 5:30 p.m.

12. Catch Shares Committee Meeting: March 8, 2012, 8:30 a.m. Until 10 a.m.

The Catch Shares Committee will receive a presentation on a voluntary catch share program and take action as appropriate.

13. Snapper Grouper Committee Meeting: March 8, 2012, 10 a.m. Until 5 p.m.

The Snapper Grouper Committee will receive updates on the status of catches versus quotas for species under quota management and address any necessary actions as the result of these reports. The Committee will receive a report on Oculina research activities and updates on the status of amendments under review, including: Regulatory Amendment 11, which proposes elimination of the current 240′ restriction on the harvest of some deepwater species within the snapper grouper management unit; the Comprehensive Annual Catch Limit (ACL) Amendment, which establishes ACL and AM for species that are not currently undergoing overfishing; Amendment 24 establishing a rebuilding plan for red grouper; Amendment 18A addressing black sea bass management and data collection; and Amendment 20A pertaining to the wreckfish ITQ program.

The Committee will also review Amendment 18B that includes measures to limit participation in the commercial golden tilefish fishery. The Committee will receive a summary of comments from recent public hearings, choose preferred alternatives for actions, modify the amendment as appropriate and provide recommendations to the Council. Additionally, the Committee will receive an overview of Regulatory Amendment 12 regarding a framework action to adjust the golden tilefish ACL, OY and ACT based on the most recent stock assessment. The Committee will choose preferred alternatives and modify the amendment as appropriate. The Committee will discuss limiting the number of black sea bass commercial trips, receive an overview of Amendment 20B addressing modifications to the wreckfish ITQ program, discuss relevant actions in CE–BA3, receive a presentation on National Marine Protected Areas (MPA), and provide recommendations as appropriate.

Note: A public comment session will be held on March 8, 2012, beginning at 5:30 p.m., on Snapper Grouper Amendment 18B, Snapper Grouper Regulatory Amendment 11, Snapper Grouper Regulatory Amendment 12 (framework action adjusting the golden tilefish ACL), Golden Crab Amendment 6, and Spiny Lobster Amendment 11, followed by comment on any other item on the agenda.

Council Session: March 9, 2012, 8:30 a.m. Until 1:30 p.m.

From 8:30 a.m. until 8:45 a.m., the Council will call the meeting to order, adopt the agenda, and approve the December 2011 meeting minutes.

From 8:45 a.m. until 9 a.m., the Council will receive a report from the Ad Hoc Data Collection Committee, consider recommendations and take action as appropriate.

From 9 a.m. until 9:15 a.m., the Council will receive a report from the Law Enforcement Committee, consider recommendations and take action as appropriate.

From 9:15 a.m. until 9:30 a.m., the Council will receive a report from the Spiny Lobster Committee, approve Spiny Lobster Amendment 11 for formal Secretarial review and approval, consider recommendations and take action as appropriate.

From 9:30 a.m. until 9:45 a.m., the Council will receive a report from the Ecosystem-Based Management Committee, consider recommendations and take action as appropriate.

From 9:45 a.m. until 10 a.m., the Council will receive a report from the King and Spanish Mackerel Committee, approve Mackerel Amendments 20 and 21 for public scoping, consider other recommendations and take action as appropriate.

From 10 a.m. until 10:15 a.m., the Council will receive a report from the Shrimp Committee, consider recommendations and take action as appropriate.

From 10:15 a.m. until 10:30 a.m., the Council will receive a report from the Information and Education Committee, consider recommendations and take action as appropriate.

From 10:30 a.m. until 10:45 a.m., the Council will receive a report from the Executive Finance Committee, approve the CY2012 activities schedule and budget, consider recommendations and take action as appropriate.

From 10:45 a.m. until 11 a.m., the Council will receive a report from the SEDAR Committee, consider recommendations and take action as appropriate.

From 11 a.m. until 11:15 a.m., the Council will receive a report from the Golden Crab Committee, approve Golden Crab Amendment 6 for formal Secretarial review and approval, consider other recommendations and take action as appropriate.

From 11:15 a.m. until 11:30 a.m., the Council will receive a report from the Catch Shares Committee, consider recommendations and take action as appropriate.

From 11:30 a.m. until 12 noon, the Council will receive a report from the Snapper Grouper Committee, approve Snapper Grouper Amendment 18B and Regulatory Amendment 12 for formal Secretarial review and approval, consider other recommendations and take action as appropriate.

From 12 noon until 1:30 p.m., the Council will receive status reports from the NOAA Fisheries Southeast Regional Office, NOAA Fisheries Southeast Science Center, review and develop recommendations on Experimental Fishing Permits as necessary, review agency and liaison reports, and discuss other business, including upcoming meetings.

Documents regarding these issues are available from the Council office (see **ADDRESSES**).

Although non-emergency issues not contained in this agenda may come before this Council for discussion, those issues may not be the subjects of formal final Council action during these meetings. Council action will be restricted to those issues specifically listed in this notice and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Act, provided the public has been notified of the Council's intent to take final action to address the emergency.

Except for advertised (scheduled) public hearings and public comment, the times and sequence specified on this agenda is subject to change.

Special Accommodations

These meetings are physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to the Council office (see **ADDRESSES**) by February 24, 2012.

Dated: February 13, 2012.

Tracey L. Thompson,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2012–3670 Filed 2–15–12; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

United States Patent and Trademark Office

Submission for OMB Review; Comment Request

The United States Patent and Trademark Office (USPTO) will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. 35).

Agency: United States Patent and Trademark Office (USPTO).

Title: Public User ID Badging.

Form Number(s): PTO–2030, PTO–2224.

Agency Approval Number: 0651–0041.

Type of Request: Revision of a currently approved collection.

Burden: 989 hours annually.

Number of Respondents: 10,003 responses per year.

Avg. Hours Per Response: The USPTO expects that it will take the public approximately 5 to 10 minutes (0.08 to 0.17 hours) to gather the necessary information, create the document, and submit the completed request.

Needs and Uses: The USPTO is required by 35 U.S.C. 41(i)(1) to maintain a Public Search Facility to provide patent and trademark collections for searching and retrieval of information. The USPTO issues online access cards to customers who wish to use the electronic search systems at the Public Search Facility. Under the authority provided in 41 CFR part 102–81, the USPTO also issues security identification badges to members of the public who wish to use the facilities at the USPTO. The public uses this information collection to request an online access card or a security identification badge and to register for the free user training classes.

Affected Public: Businesses or other for-profits.

Frequency: On occasion.

Respondent's Obligation: Required to obtain or retain benefits.

OMB Desk Officer: Nicholas A. Fraser, email: *Nicholas_A._Fraser@omb.eop.gov.*

Once submitted, the request will be publicly available in electronic format through the Information Collection Review page at *www.reginfo.gov.*

Paper copies can be obtained by:

- *Email: InformationCollection@uspto.gov.* Include ''0651–0041 copy request'' in the subject line of the message.
- *Mail:* Susan K. Fawcett, Records Officer, Office of the Chief Information

Officer, United States Patent and Trademark Office, P.O. Box 1450, Alexandria, VA 22313–1450.

Written comments and recommendations for the proposed information collection should be sent on or before March 19, 2012 to Nicholas A. Fraser, OMB Desk Officer, via email to *Nicholas_A._Fraser@omb.eop.gov,* or by fax to 202–395–5167, marked to the attention of Nicholas A. Fraser.

Dated: February 13, 2012.

Susan K. Fawcett,

Records Officer, USPTO, Office of the Chief Information Officer.

[FR Doc. 2012–3617 Filed 2–15–12; 8:45 am]

BILLING CODE 3510–16–P

DEPARTMENT OF DEFENSE

Office of the Secretary

National Security Education Board Members Meeting

AGENCY: Under Secretary of Defense for Personnel and Readiness, Department of Defense (DoD).

ACTION: Notice of meeting.

SUMMARY: Pursuant to Public Law 92–463, notice is hereby given of a forthcoming meeting of the National Security Education Board. The purpose of the meeting is to review and make recommendations to the Secretary of Defense concerning requirements established by the David L. Boren National Security Education Act, Title VII of Public Law 102–183, as amended.

DATES: March 15, 2012, from 9 a.m.–2 p.m.

ADDRESSES: Defense Language and National Security Education Office, 1101 Wilson Boulevard, Suite 1210, Arlington, VA 22209.

FOR FURTHER INFORMATION CONTACT: Ms. Alison Patz, Program Analyst, Defense Language and National Security Education Office (DLNSEO), 1101 Wilson Boulevard, Suite 1210, Rosslyn, Virginia 22209–2248; (703) 696–1991. Electronic mail address: *Alison.patz@wso.whs.mil.*

SUPPLEMENTARY INFORMATION: The National Security Education Board Members meeting is open to the public. The public is afforded the opportunity to submit written statements associated with DLNSEO.

Dated: February 13, 2012.

Aaron Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2012–3621 Filed 2–15–12; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Defense Acquisition Regulations System

[Docket No. DARS–2011–0071–0002]

Submission for OMB Review; Comment Request

ACTION: Notice.

The Defense Acquisition Regulations System has submitted to OMB for clearance, the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. chapter 35).

Dates: Consideration will be given to all comments received by March 19, 2012.

Title, Associated Forms and OMB Number: Information Collection in Support of the DoD Acquisition Process (Various Miscellaneous Requirements), Defense Federal Acquisition Regulation Supplement (DFARS) parts 208, 209, and 235 and associated clauses in part 252, OMB Control Number 0704–0187.

Type of Request: Extension.

Number of Respondents: 573.

Responses per Respondent: Approximately 2.

Annual Responses: 1,144.

Average Burden per Response: Approximately 1.5 hours.

Annual Burden Hours: 1,628.

Needs and Uses: This information collection requirement pertains to information required in DFARS parts 208, 209, 235, and associated clauses in part 252 that an offeror must submit to DoD in response to a request for proposals, an invitation for bids, or a contract requirement. DoD uses this information to—

- Determine whether to provide precious metals as Government-furnished material;
- Determine an entity's eligibility for award of a contract due to ownership or control by the government of a terrorist country;
- Determine an entity's eligibility for award of a contract under a national security program due to ownership or control by a foreign government;
- Determine whether there is a compelling reason for a contractor to enter into a subcontract in excess of $30,000 with a firm, or subsidiary of a firm, that is identified in the List of Parties Excluded from Federal Procurement and Nonprocurement as being ineligible for award of Defense subcontracts because it is owned or controlled by the government of a terrorist country;
- Evaluate claims of indemnification for losses or damages occurring under a research and development contract; and
- Keep track of radio frequencies on electronic equipment under research and development contracts so that the user does not override or interfere with the use of that frequency by another user.

Affected Public: Businesses or other for-profit and not-for-profit institutions.

Frequency: On occasion.

Respondent's Obligation: Required to obtain or maintain benefits.

OMB Desk Officer: Ms. Jasmeet Seehra.

Written comments and recommendations on the proposed information collection should be sent to Ms. Seehra at the Office of Management and Budget, Desk Officer for DoD, Room 10236, New Executive Office Building, Washington, DC 20503.

You may also submit comments, identified by docket number and title, by the following method:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the instructions for submitting comments.

Instructions: All submissions received must include the agency name, docket number, and title for the **Federal Register** document. The general policy for comments and other public submissions from members of the public is to make these submissions available for public viewing on the internet at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information provided. To confirm receipt of your comment(s), please check *http://www.regulations.gov* approximately two to three days after submission to verify posting (except allow 30 days for posting of comments submitted by mail).

DoD Clearance Officer: Ms. Patricia Toppings.

Written requests for copies of the information collection proposal should be sent to Ms. Toppings at WHS/ESD/Information Management Division, 4800 Mark Center Drive, 2nd Floor, East Tower, Suite 02G09, Alexandria, VA 22350–3100.

Ynette R. Shelkin,

Editor, Defense Acquisition Regulations System.

[FR Doc. 2012–3657 Filed 2–15–12; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF EDUCATION

Notice of Proposed Waiver and Extension of Project Period for the Native Hawaiian Career and Technical Education Program

AGENCY: Office of Vocational and Adult Education, Department of Education.

ACTION: Notice.

SUMMARY: For 36-month projects funded in fiscal year (FY) 2009 under the Native Hawaiian Career and Technical Education Program (NHCTEP), CFDA Number: 84.259A, the Secretary proposes to waive the regulation that restricts project period extensions involving the obligation of additional Federal funds. The Secretary also proposes to extend the project period of these grants for an additional 12 months. This would enable the eight current NHCTEP grantees to seek FY 2012 continuation awards for project periods through FY 2013. Further, the waiver and extension, as proposed, would mean that we would not announce new awards in FY 2012.

DATES: We must receive your comments on or before March 19, 2012.

ADDRESSES: Submit all comments on this notice to Linda Mayo, U.S. Department of Education, 400 Maryland Avenue SW., Room 11075, Potomac Center Plaza, Washington, DC 20202–7241.

If you prefer to send your comments by email, use the following address: *linda.mayo@ed.gov.* You must include the term ''Proposed Waiver and Extension for NHCTEP'' in the subject line of your message.

FOR FURTHER INFORMATION CONTACT: Linda Mayo by telephone at (202) 245–7792 or by email at: *linda.mayo@ed.gov.*

If you use a telecommunications device for the deaf (TDD), call the Federal Relay Service (FRS), toll free, at 1–800–877–8339.

SUPPLEMENTARY INFORMATION:

Invitation to Comment

We invite you to submit comments regarding this notice. We are particularly interested in receiving comments on the potential impact that this proposed project period waiver and extension might have on NHCTEP and on potential applicants that would be eligible to apply for grant awards under any new NHCTEP notice inviting applications, should there be one.

Eligible applicants are:

(1) Community-based organizations primarily serving and representing Native Hawaiians. For purposes of NHCTEP, a community-based organization means a public or private organization that provides career and technical education, or related services, to individuals in the Native Hawaiian community.

(2) Consortia of community-based organizations primarily serving and representing Native Hawaiians (34 CFR 75.127).

During and after the comment period, you may inspect all public comments about this proposed waiver and extension in room 11075, Potomac Center Plaza, 550 12th Street SW., Washington, DC, between the hours of 8:30 a.m. and 4 p.m., Washington, DC time, Monday through Friday of each week, except Federal holidays.

Assistance to Individuals with Disabilities in Reviewing the Rulemaking Record: On request we will provide an appropriate accommodation or auxiliary aid to an individual with a disability who needs assistance to review the comments or other documents in the public rulemaking record for this proposed waiver and extension. If you want to schedule an appointment for this type of aid, please contact one of the persons listed under **FOR FURTHER INFORMATION CONTACT**.

Background

NHCTEP supports grants to community-based organizations primarily serving and representing Native Hawaiians to plan, conduct, and administer career and technical education programs, as authorized by section 116(h) of the Carl D. Perkins Career and Technical Education Act of 2006 (Perkins Act or Act) (20 U.S.C. 2326(h)). The eight current NHCTEP grantees were selected based on the March 24, 2009, notice inviting applications published in the **Federal Register** (74 FR 12333) (March 24, 2009 notice).

In FY 2009, the Department funded NHCTEP projects that are scheduled to end in FY 2012. For those projects, the Secretary proposes to waive the requirement of 34 CFR 75.261(c)(2) of the Education Department General Administrative Regulations (EDGAR), which generally prohibits project period extensions involving the obligation of additional Federal funds. The Secretary also proposes to extend the current NHCTEP project period for 12 months. This would allow the eight current NHCTEP grantees to seek continuation awards in FY 2012 for project periods through FY 2013.

The Secretary makes these proposals because section 9 of the Perkins Act, which includes authorization for NHCTEP at section 116(h), authorizes appropriations for NHCTEP through FY 2012 (20 U.S.C. 2307). With the potential for changes in the authorizing legislation for NHCTEP beyond 2012, we do not believe it would be advisable to hold a new NHCTEP competition in FY 2012 for projects that may then operate for just one year. We are generally reluctant to announce a competition under which eligible entities would be expected to proceed through the application preparation and submission process while lacking critical information about the future of the program, and we do not think that it would be in the public interest to do so in this case.

Rather than holding a new competition in FY 2012, we believe that it would be in the public interest and preferable for NHCTEP for us to review requests for FY 2012 continuation awards from the eight current grantees selected based on the March 24, 2009, notice and to extend currently funded projects, for one more year, through FY 2013.

The extension of the project period and waiver of 34 CFR 75.261(c)(2) we are proposing would mean that: (1) Current grantees would be authorized to request and receive NHCTEP continuation awards in FY 2012 for project periods through FY 2013, (2) we would not announce a new competition or make new awards in FY 2012, (3) the March 24, 2009, notice would continue to govern current projects during the extension year, and (4) the eight currently-approved applications selected based on the March 24, 2009, notice would govern continuation activities.

The March 24, 2009, notice: (1) Established a project period of up to 36 months and reiterated that funding for multi-year awards would be dependent on a grantee meeting the requirements of 34 CFR 75.253 (continuation of a multi-year project after the first budget period); (2) explained the requirements of the program; (3) described the evaluation and reporting requirements; and (4) established the Government Performance and Results Act (GPRA) indicators for NHCTEP.

With this proposed extension of the project period and waiver of 34 CFR 75.261(c)(2), we propose to extend the project period of the eight current NHCTEP grantees that received grants under the FY 2009 competition for one additional year through FY 2013 with FY 2012 funds Congress has appropriated under the current statutory authority. If the waiver of 34 CFR 75.261(c)(2) that we propose in this notice is announced by us in a final notice, the requirements applicable to continuation awards for current NHCTEP grantees and the requirements in section 75.253 of EDGAR would apply to any continuation awards sought by current NHCTEP grantees.

If we announce this proposed waiver and extension as final, we will make decisions regarding annual continuation awards based on grantee program narratives, budgets and budget narratives, and performance reports, and based on the regulations in 34 CFR 75.253. We would award continuation grants based on information provided to us by each grantee, indicating that it is making substantial progress performing its NHCTEP grant activities based on the requirements in the March 24, 2009, notice inviting applications. Any activities to be carried out during the continuation year must be consistent with, or be a logical extension of the scope, goals, and objectives of each grantee's application as approved in the 2009 NHCTEP competition. Under this proposed waiver and extension, the project period for current NHCTEP grantees would be extended through FY 2013.

Regulatory Flexibility Act Certification

The Secretary certifies that the proposed waiver and extension and the activities required to support additional year of funding would not have a significant economic impact on a substantial number of small entities. The small entities that would be affected by this proposed waiver and extension are the eight currently-funded NHCTEP grantees.

The Secretary certifies that the proposed waiver and extension would not have a significant economic impact on these NHCTEP entities because the proposed waiver and extension impose minimal compliance costs to extend projects already in existence, and the activities required to support the additional year of funding would not impose additional regulatory burdens or require unnecessary Federal supervision.

Paperwork Reduction Act of 1995

This notice of proposed waiver and extension does not contain any information collection requirements.

Intergovernmental Review

The NHCTEP is not subject to Executive Order 12372 and the regulations in 34 CFR part 79.

Accessible Format: Individuals with disabilities can obtain this document in an accessible format (e.g., braille, large print, audiotape, or compact disc) on request to the contact person listed under **FOR FURTHER INFORMATION CONTACT**.

Electronic Access to This Document: The official version of this document is the document published in the **Federal Register.** Free Internet access to the official edition of the **Federal Register** and the Code of Federal Regulations is available via the Federal Digital System at: *www.gpo.gov/fdsys.* At this site you can view this document, as well as all other documents of this Department published in the **Federal Register,** in text or Adobe Portable Document Format (PDF). To use PDF you must have Adobe Acrobat Reader, which is available free at this site.

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Program Authority: 20 U.S.C. 2326(h).

Dated: February 13, 2012.

Brenda Dann-Messier,

Assistant Secretary for Vocational and Adult Education.

[FR Doc. 2012–3673 Filed 2–15–12; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

Native American Career and Technical Education Program; Proposed Waivers and Extension of the Project Period; CFDA Number 84.101A

AGENCY: Office of Vocational and Adult Education, Department of Education.

ACTION: Notice.

SUMMARY: For 60-month projects funded in fiscal year (FY) 2007 under the Native American Career and Technical Education Program (NACTEP), the Secretary proposes to waive the regulations that generally restrict project periods to 60 months and that restrict project period extensions involving the obligation of additional Federal funds. The Secretary also proposes to extend the current NACTEP project periods through FY 2013. These proposed waivers and extension of the project period would enable the 30 current NACTEP grantees to request and continue to receive Federal funding beyond the 60-month limitation contained in the Department's regulations. Further, the waivers and extension, as proposed, would mean that we would not announce new awards in FY 2012.

DATES: We must receive your comments on or before March 19, 2012.

ADDRESSES: Submit all comments on this notice to Gwen Washington, U.S. Department of Education, 400 Maryland Avenue SW., room 11076, Potomac Center Plaza, Washington, DC 20202–7241; or Linda Mayo, U.S. Department of Education, 400 Maryland Avenue SW., Room 11075, Potomac Center Plaza, Washington, DC 20202–7241.

If you prefer to send your comments by email, use one of the following addresses: *gwen.washington@ed.gov* or *linda.mayo@ed.gov.* You must include the term ''Proposed Waivers and Extension for NACTEP'' in the subject line of your message.

FOR FURTHER INFORMATION CONTACT: Gwen Washington, by telephone: (202) 245–7790, or by email: *gwen.washington@ed.gov;* or Linda Mayo, by telephone: (202) 245–7792, or by email: *linda.mayo@ed.gov.*

If you use a telecommunications device for the deaf (TDD), call the Federal Relay Service (FRS), toll free, at 1–800–877–8339.

SUPPLEMENTARY INFORMATION:

Invitation to Comment: We invite you to submit comments regarding this notice. We are particularly interested in receiving comments on the potential impact that these proposed waivers and extension may have on NACTEP and on potential applicants that would be eligible to apply for grant awards under any new NACTEP notice inviting applications, should there be one.

Eligible applicants for NACTEP are:

(a) Federally-recognized Indian tribes.

(b) Tribal organizations.

(c) Alaska Native entities.

(d) Bureau-funded schools,[1] except for Bureau-funded schools proposing to use their awards to support secondary school career and technical education programs.

(e) Consortia of one or more eligible tribes, tribal organizations, Alaska Native entities, or eligible Bureau-funded schools.

During and after the comment period, you may inspect all public comments about these proposed waivers and extension in room 11076 or room 11075, Potomac Center Plaza, 550 12th Street SW., Washington, DC, between the hours of 8:30 a.m. and 4 p.m., Washington, DC time, Monday through Friday of each week, except Federal holidays.

Assistance to Individuals with Disabilities in Reviewing the Rulemaking Record: On request, we will provide an appropriate accommodation or auxiliary aid to an individual with a disability who needs assistance to review the comments or other documents in the public rulemaking record for this notice of proposed waivers and extension. If you want to schedule an appointment for this type of aid, please contact the person listed

[1] Section 116(a)(2) of the Carl D. Perkins Career and Technical Education Act of 2006 defines the term ''Bureau-funded school'' as having the meaning given the term in section 1141 of the Education Amendments of 1978 (25 U.S.C. 2021).

under **FOR FURTHER INFORMATION CONTACT**.

Background

Current NACTEP grantees, selected based on the March 23, 2007, NACTEP notice inviting applications published in the **Federal Register** (72 FR 13770) (March 23, 2007, notice), operate career and technical education programs, as authorized by section 116(a) through (g) of the Carl D. Perkins Career and Technical Education Act of 2006 (Perkins Act or Act) (20 U.S.C. 2326(a)–(g)). The project period for the 30 NACTEP grantees is scheduled to end in FY 2012. For these projects, the Secretary proposes to waive the requirements of 34 CFR 75.250 and 34 CFR 75.261(c)(2), which limit project periods extending beyond 60 months and restrict project period extensions that involve the obligation of additional Federal funds. The Secretary also proposes to extend the current project period through FY 2013. The proposed waivers and extension would enable the 30 current NACTEP grantees to request and continue to receive Federal funds beyond the 60-month limitation set by 34 CFR 75.250, for one more year, through FY 2013.

The Secretary makes these proposals because section 9 of the Perkins Act authorizes appropriations for activities under section 116 of the Act through FY 2012 (20 U.S.C. 2307). With the potential for changes in the authorizing legislation for NACTEP beyond 2012, we do not believe it would be advisable to hold a new competition for multi-year awards under NACTEP in FY 2012 for projects that may then operate for just one year. We are generally reluctant to announce a competition under which eligible entities would be expected to proceed through the application process while lacking critical information about the future of the program, and we do not think that it would be in the public interest to do so in this case.

Rather than holding a new competition in FY 2012, we believe that it would be in the public interest and preferable for NACTEP for us to review requests for FY 2012 continuation awards from the 30 current grantees selected based on the March 23, 2007, notice and to extend currently funded projects, for one more year, through FY 2013. In lieu of announcing a new competition for this program in 2012, the Secretary proposes to waive the requirement in 34 CFR 75.250, which limits project periods to 60 months, and in 34 CFR 75.261(c)(2), which restricts project period extensions involving the obligation of additional Federal funds.

With these proposed waivers and extension of the project period, currently-funded NACTEP grantees selected based on the March 23, 2007, notice inviting applications could be continued through the FY 2013 budget and project period and we would not announce a new NACTEP competition in 2012.

If these proposed waivers and extension of the project period are announced by us in a final notice, the requirements applicable to continuation awards for current NACTEP grantees selected based on the March 23, 2007, notice inviting applications and the requirements in 34 CFR 75.253 would apply to any continuation awards sought by current NACTEP grantees. If we announce these waivers and extension as final, we will base our decisions regarding continuation awards on the program narratives, budgets, budget narratives, and program performance reports submitted by current grantees, and the requirements in 34 CFR 75.253. Any activities to be carried out during the year of the continuation award would have to be consistent with, or be a logical extension of, the scope, goals, and objectives of each grantee's application as approved in the 2007 NACTEP competition. If we publish these proposed waivers and extension as final, we would award continuation grants based on information provided to us by each grantee, indicating that it is making substantial progress performing its NACTEP grant activities.

The proposed extension of the project period and waivers of 34 CFR 75.250 and 75.261(c)(2) would not exempt the current NACTEP grantees from the appropriation account-closing provisions of 31 U.S.C. 1552(a), nor would they extend the availability of funds previously awarded to current NACTEP grantees. As a result of 31 U.S.C. 1552(a), appropriations available for a limited period may be used for payment of valid obligations for only five years after the expiration of their period of availability for Federal obligation. After that time, the unexpended balance of those funds is canceled and returned to the U.S. Treasury Department and is unavailable for restoration for any purpose (31 U.S.C. 1552(b)).

Regulatory Flexibility Act Certification

The Secretary certifies that the proposed waivers and extension would not have a significant economic impact on a substantial number of small entities.

The small entities that would be affected by these proposed waivers and extension are the 30 grantees selected based on the March 23, 2007, notice currently receiving Federal funds.

The Secretary certifies that the proposed waivers and extension would not have a significant economic impact on these entities because the proposed waivers and extension impose minimal compliance costs to extend projects already in existence, and the activities required to support the additional year of funding would not impose additional regulatory burdens or require unnecessary Federal supervision.

Paperwork Reduction Act of 1995

This notice of proposed waivers and extension does not contain any information collection requirements.

Intergovernmental Review

The NACTEP is not subject to Executive Order 12372 and the regulations in 34 CFR part 79.

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You may also access documents of the Department published in the **Federal Register** by using the article search feature at: *www.federalregister.gov.* Specifically, through the advanced search feature at this site, you can limit your search to documents published by the Department.

Program Authority: 20 U.S.C. 2326(a) through (g).

Dated: February 13, 2012.

Brenda Dann-Messier,

Assistant Secretary for Vocational and Adult Education.

[FR Doc. 2012–3676 Filed 2–15–12; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

Tribally Controlled Postsecondary Career and Technical Institutions Program; Proposed Waivers and Extension of the Project Period; CFDA Number 84.245A

AGENCY: Office of Vocational and Adult Education, Department of Education.

ACTION: Notice.

SUMMARY: For 60-month projects funded in fiscal year (FY) 2007 under the Tribally Controlled Postsecondary Career and Technical Institutions Program (TCPCTIP), the Secretary proposes to waive the regulations that generally limit project periods to 60 months and that restrict project period extensions involving the obligation of additional Federal funds. The Secretary also proposes to extend the project period for current TCPCTIP grantees through FY 2013, or longer, if Congress continues to appropriate funds under the existing program authority. The proposed waivers and extension would enable the two current TCPCTIP grantees to request and continue to receive Federal funding beyond the 60-month limitation contained in the Department's regulations, so long as the grantees are meeting the TCPCTIP requirements. Further, the waivers and extension, as proposed, would mean that we would not announce a new competition in FY 2012 or make new awards in that year, or in future years, if Congress continues to appropriate funds under the existing program authority.

DATES: We must receive your comments on or before March 19, 2012.

ADDRESSES: Submit all comments on this notice to Gwen Washington, U.S. Department of Education, 400 Maryland Avenue SW., room 11076, Potomac Center Plaza, Washington, DC 20202–7241.

If you prefer to send your comments by email, use the following address: *gwen.washington@ed.gov.* You must include the term ''Proposed Waivers and Extension for TCPCTIP'' in the subject line of your message.

FOR FURTHER INFORMATION CONTACT: Gwen Washington. Telephone: (202) 245–7792, or by email: *gwen.washington@ed.gov.*

If you use a telecommunications device for the deaf (TDD), call the Federal Relay Service (FRS), toll free, at 1–800–877–8339.

SUPPLEMENTARY INFORMATION:

Invitation to Comment: We invite you to submit comments regarding this notice. We are particularly interested in receiving comments on the potential impact that these proposed waivers and extension may have on TCPCTIP and on potential applicants that may be eligible to apply for grant awards under any new TCPCTIP notice inviting applications, should there be one.

Eligible applicants for TCPCTIP are tribally controlled postsecondary career and technical institutions that do not receive Federal support under the Tribally Controlled College or University Assistance Act of 1978 (25 U.S.C. 1801 *et seq.*) or the Navajo Community College Act (25 U.S.C. 640a *et seq.*).

During and after the comment period, you may inspect all public comments about these proposed waivers and extension for TCPCTIP in room 11076, Potomac Center Plaza, 550 12th Street, SW., Washington, DC, between the hours of 8:30 a.m. and 4 p.m., Washington, DC time, Monday through Friday of each week, except Federal holidays.

Assistance to Individuals with Disabilities in Reviewing the Rulemaking Record: On request we will provide an appropriate accommodation or auxiliary aid to an individual with a disability who needs assistance to review the comments or other documents in the public rulemaking record for this notice of proposed waivers and extension. If you want to schedule an appointment for this type of aid, please contact the person listed under **FOR FURTHER INFORMATION CONTACT**.

Background

Current TCPCTIP grantees, selected based on the May 15, 2007, TCPCTIP notice inviting applications published in the **Federal Register** (72 *FR* 27297) (May 15, 2007, notice), operate career and technical education programs as authorized by section 117 of the Carl D. Perkins Career and Technical Education Act of 2006 (Perkins Act or Act) (20 U.S.C. 2327).

The project period for the two TCPCTIP grantees is scheduled to end in FY 2012. For these projects, the Secretary proposes to waive the requirements of 34 CFR 75.250 and 34 CFR 75.261(c)(2), which limit project periods to 60 months and restrict project period extensions that involve the obligation of additional Federal funds. The Secretary also proposes to extend the project period for the two current TCPCTIP grantees through FY 2013, or longer, if Congress continues to appropriate funds under the existing program authority. The proposed waivers and extension would enable the two current TCPCTIP grantees to request and continue to receive Federal funds beyond the 60-month limitation set by 34 CFR 75.250.

The Secretary makes these proposals because section 117(i) of the Perkins Act authorizes appropriations for activities under section 117 of the Act, through FY 2012 (20 U.S.C. 2327(i)). With the potential for changes in the authorizing legislation for the TCPCTIP beyond 2012, we do not believe it would be advisable to hold a new TCPCTIP competition in FY 2012 for projects that may then operate for just one year. We are generally reluctant to announce a competition under which eligible entities would be expected to proceed through the application process while lacking critical information about the future of the program, and we do not think that it would be in the public interest to do so in this case.

Rather than holding a new competition in FY 2012, we believe that it is in the public interest and preferable for TCPCTIP for us to review requests for continuation awards from the two grantees based on the May 15, 2007, notice and extend the currently funded projects through FY 2013, or longer, if Congress continues to appropriate funds for TCPCTIP under the existing program authority. In lieu of announcing new competitions for TCPCTIP in FY 2012, the Secretary proposes to waive the requirement in 34 CFR 75.250, which limits project periods to 60 months, and in 34 CFR 75.261(c)(2), which restricts project period extensions involving the obligation of additional Federal funds.

With these proposed waivers and extension, current TCPCTIP grantees selected based on the May 15, 2007, notice inviting applications could be continued at least through the FY 2013 budget and project periods, or longer, if Congress continues to appropriate funds for TCPCTIP under the existing program authority.

If these proposed waivers and extension are announced by us in a final notice, the requirements applicable to continuation awards for current TCPCTIP grantees selected based on the May 15, 2007, notice inviting applications and the requirements in 34 CFR 75.253 would apply to any continuation awards sought by current TCPCTIP grantees. If we announce these proposed waivers and extension as final, we will base our decisions regarding annual continuation awards on the program narratives, budgets, budget narratives, and program performance reports, submitted by current grantees, and the requirements in 34 CFR 75.253. Any activities to be carried out during the year or years of continuation awards would have to be consistent with, or be a logical extension of, the scope, goals, and objectives of each grantee's application, as approved following the 2007 TCPCTIP competition. If we publish the proposed waivers and extension as final, we would award continuation grants based on information provided to us by each grantee, indicating that it is making substantial progress performing its TCPCTIP grant activities.

The proposed extension of the project period and waivers of 34 CFR 75.250 and 75.261(c)(2) would not exempt the current TCPCTIP grantees from the appropriation account-closing provisions of 31 U.S.C. 1552(a), nor would they extend the availability of funds previously awarded to current TCPCTIP grantees. As a result of 31 U.S.C. 1552(a), appropriations available for a limited period may be used for payment of valid obligations for only five years after the expiration of their period of availability for Federal obligation. After that time, the unexpended balance of those funds is canceled and returned to the U.S. Treasury Department and is unavailable for restoration for any purpose (31 U.S.C. 1552(b)).

Regulatory Flexibility Act Certification

The Secretary certifies that the proposed waivers and extension would not have a significant economic impact on a substantial number of small entities.

The small entities that would be affected by these proposed waivers and extension are the two grantees selected based on the May 15, 2007, notice currently receiving Federal funds.

The Secretary certifies that the proposed waivers and extension would not have a significant economic impact on these entities because the proposed waivers and extension impose minimal compliance costs to extend projects already in existence, and the activities required to support the additional year or years of funding would not impose additional regulatory burdens or require unnecessary Federal supervision.

Paperwork Reduction Act of 1995

This notice of proposed waivers and extension does not contain any information collection requirements.

Intergovernmental Review

The TCPCTIP is not subject to Executive Order 12372 and the regulations in 34 CFR part 79.

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Program Authority: 20 U.S.C. 2327.

Dated: February 13, 2012.

Brenda Dann-Messier,

Assistant Secretary for Vocational and Adult Education.

[FR Doc. 2012–3674 Filed 2–15–12; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

DOE/NSF Nuclear Science Advisory Committee

AGENCY: Department of Energy, Office of Science.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the DOE/NSF Nuclear Science Advisory Committee (NSAC). The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of these meetings be announced in the **Federal Register**.

DATES: Friday, March 9, 2012, 9 a.m.–5 p.m.

ADDRESSES: Marriott Bethesda North Hotel & Conference Center, 5701 Marinelli Road, North Bethesda, Maryland 20852, (301) 822–9200.

FOR FURTHER INFORMATION CONTACT: Brenda L. May, U.S. Department of Energy; SC–26/Germantown Building, 1000 Independence Avenue SW., Washington, DC 20585–1290; Telephone: (301) 903–0536

SUPPLEMENTARY INFORMATION:

Purpose of Meeting: To provide advice and guidance to the Department of Energy and the National Science Foundation on scientific priorities within the field of basic nuclear science research.

Tentative Agenda: Agenda will include discussions of the following:

Friday, March 9, 2012

- Perspectives from Department of Energy and National Science Foundation
- Update from the Department of Energy and National Science Foundation's Nuclear Physics Office's
- Presentation of Plans for a Charge for Nuclear Science Community Planning
- Report on the Fundamental Physics at the Intensity Frontier Workshop
- Status on the Creation of a Strategic Plan on Accelerator Science
- Report on National Ignition Facility Workshop
- Public Comment (10-minute rule)

Public Participation: The meeting is open to the public. If you would like to file a written statement with the Committee, you may do so either before or after the meeting. If you would like to make oral statements regarding any of these items on the agenda, you should contact Brenda L. May, (301) 903–0536 or by email at: *Brenda.May@science.doe.gov*. You must make your request for an oral statement at least 5 business days before the meeting. Reasonable provision will be made to include the scheduled oral statements on the agenda. The Chairperson of the Committee will conduct the meeting to facilitate the orderly conduct of business. Public comment will follow the 10-minute rule.

Minutes: The minutes of the meeting will be available on the Nuclear Science Advisory Committee Web site at: *http://www.science.energy.gov/np/nsac*.

Issued at Washington, DC, on February 10, 2012.

LaTanya Butler,

Acting Deputy Committee Management Officer.

[FR Doc. 2012–3652 Filed 2–15–12; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Environmental Management Site-Specific Advisory Board, Oak Ridge Reservation

AGENCY: Department of Energy, DoE.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Environmental Management Site-Specific Advisory Board (EM SSAB), Oak Ridge Reservation. The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat.

770) requires that public notice of this meeting be announced in the **Federal Register**.

DATES: Wednesday, March 14, 2012, 6 p.m.

ADDRESSES: Office of Scientific and Technical Information, 1 Science.gov Way, Oak Ridge, Tennessee 37830.

FOR FURTHER INFORMATION CONTACT: Melyssa P. Noe, Federal Coordinator, Department of Energy Oak Ridge Operations Office, P.O. Box 2001, EM–90, Oak Ridge, TN 37831. Phone (865) 241–3315; Fax (865) 576–0956 or email: *noemp@oro.doe.gov* or check the Web site at *www.oakridge.doe.gov/em/ssab.*

SUPPLEMENTARY INFORMATION:

Purpose of the Board: The purpose of the Board is to make recommendations to DOE–EM and site management in the areas of environmental restoration, waste management, and related activities.

Tentative Agenda: The meeting presentation will be an update on decontamination and decommissioning work at the East Tennessee Technology Park. The presenter will be Jim Kopotic, DOE Oak Ridge.

Public Participation: The EM SSAB, Oak Ridge, welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Melyssa P. Noe at least seven days in advance of the meeting at the phone number listed above. Written statements may be filed with the Board either before or after the meeting. Individuals who wish to make oral statements pertaining to the agenda item should contact Melyssa P. Noe at the address or telephone number listed above. Requests must be received five days prior to the meeting and reasonable provision will be made to include the presentation in the agenda. The Deputy Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Individuals wishing to make public comments will be provided a maximum of five minutes to present their comments.

Minutes: Minutes will be available by writing or calling Melyssa P. Noe at the address and phone number listed above. Minutes will also be available at the following Web site: *http://www.oakridge.doe.gov/em/ssab/minutes.htm.*

Issued at Washington, DC, on February 13, 2012.

LaTanya R. Butler,

Acting Deputy Committee Management Officer.

[FR Doc. 2012–3647 Filed 2–15–12; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. IC12–2–000]

Commission Information Collection Activities; Comment Request

AGENCY: Federal Energy Regulatory Commission.

ACTION: Comment request.

SUMMARY: In compliance with the requirements of the Paperwork Reduction Act of 1995, 44 U.S.C. 3507(a)(1)(D), the Federal Energy Regulatory Commission (Commission or FERC) is submitting the information collection FERC–550, Oil Pipeline Rates: Tariff Filings, to the Office of Management and Budget (OMB) for review of the information collection requirements. Any interested person may file comments directly with OMB and should address a copy of those comments to the Commission as explained below. The Commission issued a Notice in the **Federal Register** (76 FR 76702, 12/08/2011) requesting public comments. FERC received no comments on the FERC–550 and is making this notation in its submittal to OMB.

DATES: Comments on the collection of information are due by March 19, 2012.

ADDRESSES: Comments filed with OMB, identified by the OMB Control No. 1902–0089, should be sent via email to the Office of Information and Regulatory Affairs: *oira_submission@omb.gov.* Attention: Federal Energy Regulatory Commission Desk Officer. The Desk Officer may also be reached via telephone at 202–395–4718.

A copy of the comments should also be sent to the Federal Energy Regulatory Commission, identified by the Docket No. IC12–2–000, by either of the following methods:

• *eFiling at Commission's Web Site: http://www.ferc.gov/docs-filing/efiling.asp.*

• *Mail/Hand Delivery/Courier:* Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

Instructions: All submissions must be formatted and filed in accordance with submission guidelines at: *http://www.ferc.gov/help/submission-guide.asp.* For user assistance contact FERC Online Support by email at *ferconlinesupport@ferc.gov,* or by phone at: (866) 208–3676 (toll-free), or (202) 502–8659 for TTY.

Docket: Users interested in receiving automatic notification of activity in this docket or in viewing/downloading comments and issuances in this docket may do so at *http://www.ferc.gov/docs-filing/docs-filing.asp.*

FOR FURTHER INFORMATION CONTACT: Ellen Brown may be reached by email at *DataClearance@FERC.gov,* by telephone at (202) 502–8663, and by fax at (202) 273–0873.

SUPPLEMENTARY INFORMATION:

Title: FERC–550, Oil Pipeline Rates: Tariff Filings.

OMB Control No.: 1902–0089.

Type of Request: Three-year extension of the FERC–550 information collection requirements with no changes to the reporting requirements.

Abstract: The Commission uses the information collected under the requirements of FERC–550 to implement the statutory provisions of Parts 1, 6, and 15 of the Interstate Commerce Act (ICA) (Pub. L. 337, 34 Stat. 584). Jurisdiction over oil pipelines as it relates to the establishment of valuations for pipelines was transferred from the Interstate Commerce Commission (ICC) to FERC, pursuant to sections 306 and 402 of the Department of Energy Organization Act (DOE Act), 42 U.S.C. 7155 and 7172, and Executive Order No. 12009, 42 FR 46267 (September 17, 1977).

18 CFR Parts 341–348 specifies the filing requirements for proposed oil pipeline rates. The data that oil pipelines file is the basis for Commission analyses of the rates they plan to charge to transport crude oil and petroleum products. The Commission uses its analyses: (1) To determine if the proposed charges result in just and reasonable rates for the oil pipeline's transportation services and (2) to help the Commission decide whether it should suspend, accept or reject the proposed rates.

Type of Respondents: Oil pipeline companies.

Estimate of Annual Burden[1]*:* The Commission estimates the total Public Reporting Burden for this information collection as:

[1] Burden is defined as 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. For further explanation of what is included in the information collection burden, reference 5 Code of Federal Regulations 1320.3(b)(1).

FERC–550 (IC12–2–000): OIL PIPELINE RATES: TARIFF FILINGS

	Number of respondents	Number of responses per respondent	Total number of responses	Average burden hours per response	Estimated total annual burden
	(A)	(B)	(A) × (B) = (C)		(C) × (D)
Oil pipeline companies	128	4	512	11	5,632

The total estimated annual cost burden to respondents is $385,499.24 [5,632 hours ÷ 2,080 [2] hours/year = 2.70769 years * $142,372 [3] = $385,499.24].

Comments: Comments are invited on: (1) Whether the collection of information is necessary for the proper performance of the functions of the Commission, including whether the information will have practical utility; (2) the accuracy of the agency's estimate of the burden and cost of the collection of information, including the validity of the methodology and assumptions used; (3) ways to enhance the quality, utility and clarity of the information collection; and (4) ways to minimize the burden of the collection of information on those who are to respond, including the use of automated collection techniques or other forms of information technology.

Dated: February 10, 2012.

Kimberly D. Bose,

Secretary.

[FR Doc. 2012–3663 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project Nos. 1175–015, 1290–012]

Appalachian Power Company; Notice of Application Tendered for Filing With the Commission and Establishing Procedural Schedule for Licensing and Deadline for Submission of Final Amendments

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection.

Type of Application: New Major Licenses.

Project Nos.: 1175–015 and 1290–012.

Date Filed: January 31, 2012.

Applicant: Appalachian Power Company.

Name of Project: London/Marmet and Winfield Hydroelectric Projects.

Location: The existing projects are located on the Kanawha River. The London/Marmet Project is located in Fayette and Kanawha Counties, West Virginia, and the Winfield Project is located in Kanawha and Putnam Counties, West Virginia. The London/Marmet and Winfield Projects would occupy 11.71 and 8.25 acres, respectively, of federal land managed by the U.S. Army Corp of Engineers.

Filed Pursuant to: Federal Power Act, 16 U.S.C. 791 (a)–825(r).

Applicant Contact: Harold G. Slone, Manager, Appalachian Power Company, 40 Franklin Road, Roanoke, VA 24011; Telephone (540) 985–2861.

FERC Contact: Brandi Sangunett, (202) 502–8393 or *brandi.sangunett@ferc.gov.*

This application is not ready for environmental analysis at this time.

The existing project works consists of the following:

The London/Marmet Project consists of two developments. The existing London Development utilizes the head created by the Army Corps of Engineers' (Corps) 26-foot-high London Dam located at river mile (RM) 82.8 on the Kanawha River and consists of: (1) A forebay area protected by a log boom; (2) screened intake structures; (3) a concrete powerhouse containing three turbine-generator units with a total installed capacity of 14.4 megawatts (MW); (4) a tailrace 420 feet long; (5) a substation containing two, three-phase transformers and two auxiliary transformers; (6) two, 0.38-mile-long, 46-kilovolt (kV) transmission lines; and (7) other appurtenances. The development generates about 84,048 megawatt-hours (MWh) annually.

The existing Marmet Development utilizes the head created by the Corps' 34-foot-high Marmet Dam located at RM 67.7 on the Kanawha River and consists of: (1) A forebay area protected by a log boom; (2) screened intake structures; (3) a concrete powerhouse containing three turbine-generator units with a total installed capacity of 14.4 MW; (4) a tailrace 450 feet long; (5) a substation containing two, three-phase transformers and two auxiliary transformers; (6) two, 0.78-mile-long, 46-kV transmission lines; and (7) other appurtenances. The development generates about 82,302 MWh annually.

The London/Marmet Project has a total installed capacity of 28.8 MW and generates about 166,350 MWh annually.

The existing Winfield Project utilizes the head created by the Corps' 38-foot-high Winfield Dam located at RM 31.1 on the Kanawha River and consists of: (1) A forebay area protected by a 410-foot-long log boom; (2) screened intake structures; (3) a concrete powerhouse containing three turbine-generator units with a total installed capacity of 14.76 MW; (4) a tailrace 410 feet long; (5) a substation containing a generator step-up bank of three transformers and three auxiliary transformers; (6) a 3.7-mile-long, 69-kV transmission line; and (7) other appurtenances. The project generates about 114,090 MWh annually.

The above hydroelectric facilities' operation is synchronized with the operation of the Corps' locks at each dam. The developments at each of the two projects operate within allowable pool elevation limits as established by the Corps. The London pool elevation is allowed to fluctuate between 611.0 feet and 614.0 feet National Geodetic Vertical Datum 1929 (NGVD). The Marmet pool elevation is allowed to fluctuate between 589.7 feet and 590.0 feet NGVD. The Winfield pool elevation is allowed to fluctuate between 565.8 feet and 566.0 feet NGVD. All three pools can be drawn down at a maximum rate of 0.5 feet per hour. When stream flow exceeds the maximum turbine discharge, the responsibility for control of the pool elevations passes to the Corps' personnel and the projects operate in run-of-release mode.

Appalachian is proposing to modify the maximum pool elevation limit at the London Development from 614.0 feet to 613.7 feet NGVD.

Locations of the Application: A copy of the application is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site at *http://www.ferc.gov* using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at

[2] 2,080 hours = 40 hours/week * 52 weeks (1 year).

[3] Average annual salary per employee in 2011.

FERCOnlineSupport@ferc.gov or toll-free at 1–866–208–3676, or for TTY, (202) 502–8659. A copy is also available for inspection and reproduction at the address in item (h) above.

You may also register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via email of new filings and issuances related to this or other pending projects. For assistance, contact FERC Online Support.

Procedural Schedule

The application will be processed according to the following preliminary Hydro Licensing Schedule. Revisions to the schedule may be made as appropriate.

Milestone	Target date
Notice of Ready for Environmental Analysis.	March 31, 2012.
Filing of recommendations, preliminary terms and conditions, and fishway prescriptions.	May 30, 2012.
Commission issues Non-Draft EA.	September 27, 2012.
Comments on EA	October 27, 2012.
Modified terms and conditions.	December 26, 2012.

Final amendments to the application must be filed with the Commission no later than 30 days from the issuance date of the Notice of Ready for Environmental Analysis.

Dated: February 10, 2012.

Kimberly D. Bose,

Secretary.

[FR Doc. 2012–3664 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 13739–001]

Lock+ Hydro Friends Fund XLII, LLC; Notice of Intent To File License Application, Filing of Pre-Application Document, and Approving Use of the Traditional Licensing Process

a. *Type of Filing:* Notice of Intent to File License Application and Request to Use the Traditional Licensing Process.

b. *Project No.:* 13739–001.

c. *Date Filed:* December 23, 2011.

d. *Submitted By:* Lock+ Hydro Friends Fund XLII, LLC.

e. *Name of Project:* Braddock Locks and Dam Hydroelectric Project.

f. *Location:* At the existing Braddock Locks and Dam on the Monongahela River, in Allegheny County, Pennsylvania. The project would occupy United States lands administered by the U.S. Army Corps of Engineers.

g. *Filed Pursuant to:* 18 CFR 5.3 of the Commission's regulations.

h. *Potential Applicant Contact:* Mr. Mark R. Stover, Lock+™ Hydro Friends Fund XLII, c/o Hydro Green Energy, LLC, 900 Oakmont Lane, Suite 310, Westmont, IL 60559; (877) 556–6566 ext. 711; email—mark@hgenergy.com

i. *FERC Contact:* John Mudre at (202) 502–8902; or email at *john.mudre@ferc.gov.*

j. Lock+ Hydro Friends Fund XLII, LLC filed its request to use the Traditional Licensing Process on December 23, 2011. Lock+ Hydro Friends Fund XLII, LLC provided public notice of its request on December 22, 2011. In a letter dated January 30, 2012, the Director of the Division of Hydropower Licensing approved Lock+ Hydro Friends Fund XLII, LLC's request to use the Traditional Licensing Process.

k. With this notice, we are initiating informal consultation with: (a) The U.S. Fish and Wildlife Service under section 7 of the Endangered Species Act and the joint agency regulations thereunder at 50 CFR, Part 402; and (b) the Pennsylvania State Historic Preservation Officer, as required by section 106, National Historic Preservation Act, and the implementing regulations of the Advisory Council on Historic Preservation at 36 CFR 800.2.

l. With this notice, we are designating Lock+ Hydro Friends Fund XLII, LLC as the Commission's non-federal representative for carrying out informal consultation, pursuant to section 7 of the Endangered Species Act, and section 106 of the National Historic Preservation Act.

m. Lock+ Hydro Friends Fund XLII, LLC filed a Pre-Application Document (PAD; including a proposed process plan and schedule) with the Commission, pursuant to 18 CFR 5.6 of the Commission's regulations.

n. A copy of the PAD is available for review at the Commission in the Public Reference Room or may be viewed on the Commission's Web site (*http://www.ferc.gov*), using the ''eLibrary'' link. Enter the docket number, excluding the last three digits in the docket number field to access the document. For assistance, contact FERC Online Support at *FERCONlineSupport@ferc.gov* or toll free at 1–866–208–3676, or for TTY, (202) 502–8659. A copy is also available for inspection and reproduction at the address in paragraph h.

o. Register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via email of new filing and issuances related to this or other pending projects. For assistance, contact FERC Online Support.

Dated: February 10, 2012.

Kimberly D. Bose,

Secretary.

[FR Doc. 2012–3662 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER11–2855–002; *ER11–2856–002; ER11–2857–002; ER10–2722–001; ER10–2787–001; ER10–2532–001; ER10–2488–002.*

Applicants: Oasis Power Partners, LLC, Crescent Ridge LLC, Eurus Combine Hills I LLC, Avenal Park LLC, Sand Drag LLC, Sun City Project LLC, Eurus Combine Hills II LLC.

Description: Notice of Change in Status of Avenal Park LLC, *et al.*

Filed Date: 2/7/12.

Accession Number: 20120207–5140.

Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–543–002.

Applicants: Ethical Electric Benefit Co.

Description: Ethical Electric Benefit Co. Market Based Rate Filing Revised to be effective 12/6/2011.

Filed Date: 2/7/12.

Accession Number: 20120207–5108.

Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–559–001.

Applicants: Golden Valley Wind Park, LLC.

Description: Golden Valley Tariff to be effective 2/2/2012.

Filed Date: 2/7/12.

Accession Number: 20120207–5123.

Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–560–001.

Applicants: Milner Dam Wind Park, LLC.

Description: Milner Dam Tariff to be effective 2/2/2012.

Filed Date: 2/7/12.

Accession Number: 20120207–5124.

Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–561–001.

Applicants: Oregon Trail Wind Park, LLC.

Description: Oregon Trail Tariff to be effective 2/2/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5126.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–562–001.
Applicants: Pilgrim Stage Station Wind Park, LLC.
Description: Pilgrim Stage Tariff to be effective 2/2/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5135.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–563–001.
Applicants: Thousand Springs Wind Park, LLC.
Description: Thousand Springs Tariff to be effective 2/2/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5137.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–564–001.
Applicants: Tuana Gulch Wind Park, LLC.
Description: Tuana Gulch Tariff to be effective 2/2/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5138.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–565–001.
Applicants: Camp Reed Wind Park, LLC.
Description: Camp Reed Tariff to be effective 2/2/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5122.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–566–001.
Applicants: Payne's Ferry Wind Park, LLC.
Description: Payne's Ferry Tariff to be effective 2/2/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5134.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–567–001.
Applicants: Salmon Falls Wind Park, LLC.
Description: Salmon Falls Tariff to be effective 2/2/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5136.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–568–001.
Applicants: Yahoo Creek Wind Park, LLC.
Description: Yahoo Creek Tariff to be effective 2/2/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5139.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–711–001.
Applicants: NorthWestern Corporation.
Description: Amendment to Filing of Coordinated Operating Agreement with NaturEner Wind Watch to be effective 12/21/2011.
Filed Date: 2/7/12.
Accession Number: 20120207–5100.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–1011–000.
Applicants: REP Energy LLC.
Description: REP Energy LLC Baseline Filing of its Market Based Rate Tariff to be effective 2/7/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5029.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–1015–000.
Applicants: Powerex Corp.
Description: Request for Waiver of Provision of Powerex Corp. Market-Based Rate Schedule and Request for Expedited Treatment.
Filed Date: 2/7/12.
Accession Number: 20120207–5067.
Comments Due: 5 pm ET 2/21/12.

Docket Numbers: ER12–1016–000.
Applicants: Appalachian Power Company.
Description: 20120207 Att K and L Revisions Correction to be effective N/A.
Filed Date: 2/7/12.
Accession Number: 20120207–5133.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–1017–000.
Applicants: Southwest Power Pool, Inc.
Description: 1976R1 Kaw Valley Electric Cooperative, Inc. NITSA NOA to be effective 12/1/2011.
Filed Date: 2/7/12.
Accession Number: 20120207–5104.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–1018–000.
Applicants: Southwest Power Pool, Inc.
Description: 1977R1 Nemaha-Marshall Electric Cooperative NITSA NOA to be effective 12/1/2011.
Filed Date: 2/7/12.
Accession Number: 20120207–5106.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–1019–000.
Applicants: Burley Butte Wind Park, LLC.
Description: Burley Butte Tariff—Amendment to be effective 2/1/2012. 70.
Filed Date: 2/7/12.
Accession Number: 20120207–5121.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–1020–000.
Applicants: Midwest Independent Transmission System Operator, Inc.
Description: 02–07–12 Entergy Cost Deferral Filing to be effective 6/1/2011.
Filed Date: 2/7/12.
Accession Number: 20120207–5127.
Comments Due: 5 pm ET 2/28/12.

Docket Numbers: ER12–1021–000.
Applicants: Midwest Independent Transmission System Operator, Inc.
Description: 02–07–12 CDC Cost Deferral Filing to be effective 12/1/2011.
Filed Date: 2/7/12.
Accession Number: 20120207–5128.
Comments Due: 5 pm ET 2/28/12.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 pm Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 08, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3595 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP12–371–000.
Applicants: USG Pipeline Company, LLC.
Description: Volume 2 cancellation to be effective 2/6/2012.
Filed Date: 2/6/12.
Accession Number: 20120206–5148.
Comments Due: 5 pm ET 2/21/12.

Docket Numbers: RP12–372–000.
Applicants: Gulf South Pipeline Company, LP.
Description: Create PXS Service to be effective 3/9/2012.
Filed Date: 2/7/12.
Accession Number: 20120207–5068.
Comments Due: 5 pm ET 2/21/12.

Docket Numbers: RP12–373–000.
Applicants: Questar Pipeline Company.
Description: Non-conforming TSA's version 1.0.0 to be effective 3/9/2012.
Filed Date: 2/8/12.

Accession Number: 20120208–5015.
Comments Due: 5 pm ET 2/21/12.

Docket Numbers: RP12–374–000.
Applicants: Kern River Gas Transmission Company.
Description: 2012 Clean-up Filing to be effective 3/9/2012.
Filed Date: 2/8/12
Accession Number: 20120208–5061.
Comments Due: 5 pm ET 2/21/12.

Docket Numbers: RP12–375–000.
Applicants: Natural Gas Pipeline Company of America LLC.
Description: Niska Negotiated Rate to be effective 4/1/2012.
Filed Date: 2/9/12.
Accession Number: 20120209–5019.
Comments Due: 5 pm ET 2/21/12.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and § 385.214) on or before 5 pm Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, and service can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 9, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary

[FR Doc. 2012–3597 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #2

Take notice that the Commission received the following electric corporate filings:

Docket Numbers: EC12–66–000.
Applicants: Turner Energy LLC, MoArk, LLC, DeCoster Enterprises, LLC.
Description: Joint Application for Disposition of Jurisdictional Facilities and Privileged Treatment of Exhibit I.
Filed Date: 2/7/12.
Accession Number: 20120207–5161.
Comments Due: 5 p.m. ET 2/28/12.

Docket Numbers: EC12–67–000.
Applicants: Entergy Nuclear Generation Company, Entergy Nuclear Palisades, LLC, Entergy Nuclear Power Marketing, LLC, Entergy Nuclear Vermont Yankee, LLC, Entergy Nuclear Fitzpatrick, LLC, Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, Llano Estacado Wind, LLC, Entergy Power, LLC, Northern Iowa Windpower, LLC, EAM Nelson Holding, LLC,EWO Marketing, LLC, Entergy Rhode Island State Energy, L.P.
Description: Application of EAM Nelson Holding, LLC, et al., for Section 203 Authorization.
Filed Date: 2/8/12.
Accession Number: 20120208–5043.
Comments Due: 5 p.m. ET 2/29/12.

Take notice that the Commission received the following exempt wholesale generator filings:

Docket Numbers: EG12–31–000.
Applicants: Quantum Choctaw Power, LLC.
Description: Quantum Choctaw Power Notice of Self-certification of Exempt Wholesale Generator Status.
Filed Date: 2/8/12.
Accession Number: 20120208–5011.
Comments Due: 5 p.m. ET 2/29/12.

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER12–1022–000.
Applicants: Pacific Gas and Electric Company.
Description: Request for Tariff Waiver of Pacific Gas and Electric Company.
Filed Date: 2/7/12.
Accession Number: 20120207–5162.
Comments Due: 5 p.m. ET 2/28/12.

Docket Numbers: ER12–1023–000.
Applicants: PJM Interconnection, L.L.C.
Description: PJM Original Service Agreement No. 3187; Queue No. W3–134 to be effective 1/16/2012.
Filed Date: 2/8/12.
Accession Number: 20120208–5049.
Comments Due: 5 p.m. ET 2/29/12.

Docket Numbers: ER12–1024–000.
Applicants: Carolina Power & Light Company.
Description: Cancellation of Service Agreement No. 315 under Carolina Power and Light OATT to be effective 1/20/2012.
Filed Date: 2/8/12.
Accession Number: 20120208–5062.
Comments Due: 5 p.m. ET 2/29/12.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 pm Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 8, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3596 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP12–376–000.
Applicants: Eastern Shore Natural Gas Company.
Description: RP10–1083–005 Revised Compliance Filing to be effective 7/29/2011.
Filed Date: 2/9/12.
Accession Number: 20120209–5109.
Comments Due: 5 pm ET 2/21/12.

Docket Numbers: RP12–377–000.
Applicants: Transcontinental Gas Pipe Line Company, LLC.
Description: Transcontinental Gas Pipe Line Company, LLC submits tariff filing per 154.203: Compliance Filing—Update Volume No. 2 Table of Contents to be effective 1/31/2012.
Filed Date: 2/10/12.
Accession Number: 20120210–5058.
Comments Due: 5 pm ET 2/22/12.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 pm Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

Filings in Existing Proceedings

Docket Numbers: RP11–1657–001.
Applicants: Questar Southern Trails Pipeline Company.
Description: Compliance Filing RP11–1657/RP10–388 to be effective 6/28/2010.

Filed Date: 2/9/12.
Accession Number: 20120209–5135.
Comments Due: 5 pm ET 2/21/12.

Docket Numbers: RP11–1957–004.
Applicants: Stingray Pipeline Company, L.L.C.
Description: Motion to Place Rates Into Effect to be effective 1/1/2012.
Filed Date: 2/9/12.
Accession Number: 20120209–5136.
Comments Due: 5 pm ET 2/13/12.

Docket Numbers: RP11–1674–002.
Applicants: Florida Gas Transmission Company, LLC.
Description: Compliance with RP11–1674–000 to be effective 1/20/2012.
Filed Date: 2/6/12.
Accession Number: 20120206–5071.
Comments Due: 5 pm ET 2/21/12.

Docket Numbers: RP11–1855–001.
Applicants: Florida Gas Transmission Company, LLC.
Description: Compliance with RP11–1855–000 to be effective 3/9/2012.
Filed Date: 2/6/12.
Accession Number: 20120206–5115.
Comments Due: 5 pm ET 2/21/12.

Any person desiring to protest in any of the above proceedings must file in accordance with Rule 211 of the Commission's Regulations (18 CFR 385.211) on or before 5 pm Eastern time on the specified comment date.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, and service can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary

[FR Doc. 2012–3623 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EL12–24–000]

Pioneer Transmission, LLC v. Northern Indiana Public Service Company Midwest Independent Transmission System Operator, Inc.; Notice of Complaint

Take notice that on February 8, 2012, pursuant to sections 206 and 306 of the Federal Power Act, 16 U.S.C. 824e and 825e (2006), and Rule 206 of the Commission's Rules of Practice and Procedure, 18 CFR 385.206 (2011), Pioneer Transmission, LLC (Pioneer) filed a formal complaint against Northern Indiana Public Service Company (NIPSCO) and Midwest Independent Transmission System Operator, Inc. (MISO) alleging that (1) NIPSCO does not have ownership and investment rights to any of the 765kV investment associated with the segment of the Pioneer project that MISO recently included in its 2011 regional transmission expansion plan, and (2) Pioneer should be allowed to become a party to the MISO Transmission Owners Agreement immediately and begin recovering costs (CWIP) in accordance with FERC's order approving transmission rate incentives for Pioneer.

Pioneer certifies that copies of the complaint were served on the contacts for NIPSCO and MISO as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5 p.m. Eastern Time on February 28, 2012.

Dated: February 9, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3598 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Effectiveness of Exempt Wholesale Generator Status

	Docket Nos.
Fire Island Wind, LLC	EG12–9–000
Kaheawa Wind Power II, LLC	EG12–12–000
Broken Bow Wind, LLC	EG12–13–000
Crofton Bluffs Wind, LLC	EG12–14–000
NRG Texas Power LLC	EG12–15–000
Le Plateau Wind Power L.P	FC12–1–000
Wind Invest Sp. z.o.o.	FC12–2–000
Dobieslaw Wind Invest z.o.o.	FC12–3–000
Jezycki Wind Invest Sp. z.o.o	FC12–4–000

Take notice that during the month of January 2012, the status of the above-captioned entities as Exempt Wholesale Generators or Foreign Utility Companies became effective by operation of the Commission's regulations. 18 CFR 366.7(a).

Dated: February 9, 2012.

Kimberly D. Bose,

Secretary.

[FR Doc. 2012–3654 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EL07–56–010; Docket No. EL07–58–010]

Allegheny Electric Cooperative, Inc., et al. v. PJM Interconnection, L.L.C.; Organization of PJM States, Inc., et al. v. PJM Interconnection, L.L.C.; Notice of Filing

Take notice that on February 8, 2012, the New Jersey Board of Public Utilities filed a Confidentiality Certification as required by section 18.17.4 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. and the Federal Energy Regulatory Commission's Order, *Organization of PJM States, Inc.* v. *PJM Interconnection, L.L.C.,* 122 FERC ¶ 61,257 (2008).

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant and all the parties in this proceeding.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

This filing is accessible online at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5 p.m. Eastern Time on February 29, 2012.

Dated: February 9, 2012.

Kimberly D. Bose,

Secretary.

[FR Doc. 2012–3655 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER12–1013–000]

Physical Systems Integration, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Physical Systems Integration, LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is February 29, 2012.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 9, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3594 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER12–997–000]

Lilabell Energy LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Lilabell Energy LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is February 29, 2012.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email

FERCOnlineSupport@ferc.gov. or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 9, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3599 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER12–1002–000]

AP Gas & Electric (NJ), LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of AP Gas & Electric (NJ), LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is February 29, 2012.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 9, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3601 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER12–1006–000]

AP Gas & Electric (OH), LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of AP Gas & Electric (OH), LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is February 29, 2012.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at http://www.ferc.gov. To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 9, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3603 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER12–1007–000]

AP Gas & Electric (NY), LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of AP Gas & Electric (NY), LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR Part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR Part 34, of future issuances of securities and assumptions of liability, is February 29, 2012.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov*. To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the web site that enables subscribers to receive emailnotification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 9, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3604 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER12–1005–000]

AP Gas & Electric (IL), LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of AP Gas & Electric (IL), LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR Part 34, of future issuances of securities and assumptions of liability, is February 29, 2012.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 9, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3602 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER12–999–000]

AP Gas & Electric (MD), LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of AP Gas & Electric (MD), LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is February 29, 2012.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov*. To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 14 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC

Online service, please email *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: February 9, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3600 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 13305–002]

Whitestone Power and Communications; Notice of Teleconference

a. *Date and Time of Meeting:* Tuesday, February 21, 2012, starting at 2 p.m. and ending at 4 p.m. (Eastern Standard Time).

b. *FERC Contact:* Dianne Rodman, (202) 502–6077 or *dianne.rodman@ferc.gov.*

c. *Purpose of Meeting:* Commission staff will meet with Whitestone Power and Communications (Whitestone) to discuss the need for environmental monitoring for the Microturbine Hydrokinetic River-In-Stream Energy Conversion Power Project (also known as the Whitestone Poncelet RISEC Project), which would be located on the Tanana River near Delta Junction, Alaska.

d. All local, state, and federal agencies, Indian tribes, and other interested parties are invited to participate by phone. Please call Dianne Rodman by February 16, 2012, to RSVP and to receive specific instructions on how to participate.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3632 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 13–023]

Green Island Power Authority; Notice of Meeting and Teleconference

a. *Date and Time of Meeting:* Wednesday March 21, 2012, beginning at 10 a.m. EST.

b. *Place:* Commission Headquarters, 888 First Street NE., Washington, DC 20426, Room 62–26.

c. *FERC Contact:* Tom Dean, (202) 502–6041.

d. *Purpose of Meeting:* To discuss authorizations and approvals that may be needed for, and the U.S. Army Corps of Engineers' (Corps) position on, proposed modifications to the facilities and operation of the Corps' Green Island Lock and Dam (see attached agenda for complete list of topics).

e. All local, state, and federal agencies, Indian tribes, and other interested parties are invited to participate either in person or by phone. Please call Tom Dean at (202) 502–6041 by Wednesday, March 14, 2012, to receive specific instructions on how to participate.

f. FERC conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations please send an email to *accessibility@ferc.gov* or call toll free (866) 208–3372 (voice) or 202–502–8659 (TTY), or send a FAX to 202–208–2106 with the required accommodations.

g. A summary of the teleconference will be placed in the public record for the project.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3631 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 14152–000]

Reliable Storage 1 LLC; Notice of Preliminary Permit Application Accepted for Filing and Soliciting Comments, Motions To Intervene, and Competing Applications

On March 25, 2011, Reliable Storage 1 LLC filed an application, pursuant to section 4(f) of the Federal Power Act, proposing to study the feasibility of hydropower near the town of Monterey, in Putnam County, Tennessee. The sole purpose of a preliminary permit, if issued, is to grant the permit holder priority to file a license application during the permit term. A preliminary permit does not authorize the permit holder to perform any land-disturbing activities or otherwise enter upon lands or waters owned by others without the owners' express permission.

The proposed pumped storage project would consist of the following: (1) A 70-foot-high, 7,500-foot-long earth embankment dam; (2) an upper reservoir with a surface area of 100 acres and an 7,100 acre-foot storage capacity; (3) a 120-foot-high, 920-foot-long earth embankment dam creating; (4) a lower reservoir with a surface area of 220 acres and an 7,300 acre-foot storage capacity; (5) one 30-foot-diameter, 3,200-foot-long penstock; (6) a bifurcation to three penstocks each 16-foot-diameter, and 100-foot-long; (7) an underground powerhouse/pumping station containing three pump/generating units with a total generating capacity of 600 megawatts; (8) a 30-foot-diameter, 700-foot-long tailrace tunnel; (9) a 24-foot-diameter, 2,000-foot-long access tunnel; (10) a substation; (11) a 1.4-mile-long, 500 kV transmission line to an existing distribution line; and (12) a 6,300-foot-long access road. The proposed project would have an average annual generation of 1,500,000 megawatt-hours (MWh), which would be sold to a local utility.

Applicant Contact: Mr. Daniel R. Irvin, Free Flow Power Corporation, 239 Causeway Street Suite 300, Boston MA 01244; phone (978) 252–7631.

FERC Contact: Michael Spencer, (202) 502–6093.

Deadline for filing comments, motions to intervene, competing applications (without notices of intent), or notices of intent to file competing applications: 60 days from the issuance of this notice. Competing applications and notices of intent must meet the requirements of 18 CFR 4.36. Comments, motions to intervene, notices of intent, and competing applications may be filed electronically via the Internet. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site *http://www.ferc.gov/docs-filing/efiling.asp.* Commenters can submit brief comments up to 6,000 characters, without prior registration, using the eComment system at *http://www.ferc.gov/docs-filing/ecomment.asp.* You must include your name and contact information at the end of your comments. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov;* call toll-free at (866) 208–3676; or, for TTY, contact (202) 502–8659. Although the Commission strongly encourages electronic filing, documents may also be paper-filed. To paper-file, mail an original and seven copies to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

More information about this project, including a copy of the application, can be viewed or printed on the ''eLibrary'' link of the Commission's Web site at *http://www.ferc.gov/docs-filing/elibrary.asp.* Enter the docket number (P–14152–000) in the docket number field to access the document. For assistance, contact FERC Online Support.

Dated: February 10, 2012.

Kimberly D. Bose,

Secretary.

[FR Doc. 2012–3661 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project Nos. 14181–000; 14195–000]

Lock+ Hydro Friends Fund XLIII; FFP Project 53, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on May 3, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Tombigbee River, in Greene and Sumter counties, Alabama. The applications were filed by Lock+ Hydro Friends Fund XLIII for Project No. 14181–000, and FFP Project 53, LLC for Project No. 14195–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in Room 2C, the Commission Meeting Room, located at 888 First St. NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3637 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project Nos. 14180–000; 14193–000]

Lock+ Hydro Friends Fund XLV; FFP Project 2, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on May 3, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Arkansas River, in Pulaski County, Arkansas. The applications were filed by Lock+ Hydro Friends Fund XLV for Project No. 14180–000 and FFP Project 2, LLC for Project No. 14193–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First Street NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3636 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 14178–000; Project No. 14190–000]

Lock+ Hydro Friends Fund XLVII; FFP Project 52, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on May 3, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Arkansas River, in Perry County and Faulkner County, Arkansas. The applications were filed by Lock+ Hydro Friends Fund XLVII for Project No. 14178–000, and FFP Project 52, LLC for Project No. 14190–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First St. NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3635 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 14131–000; Project No. 14138–000; Project No. 14135–000]

Riverbank Hydro No. 1, LLC; Lock+ Hydro Friends Fund XXXVII; Qualified Hydro 20, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received three preliminary permit applications deemed filed on April 1, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Tombigbee River, in Monroe County, Mississippi. The applications were filed by Riverbank Hydro No. 1, LLC for Project No. 14131–000, Lock+ Hydro Friends Fund XXXVII for Project No. 14138–000, and Qualified Hydro 20, LLC for Project No. 14135–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First St. NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3634 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 13824–000; Project No. 13826–000]

FFP Missouri 17, LLC; BOST2 Hydroelectric, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on August 6, 2010, at 8:30 a.m.,[1] for proposed projects to be located on the Ouachita River, in Caldwell Parish, Louisiana. The applications were filed by FFP Missouri 17, LLC for Project No. 13824–000 and BOST2 Hydroelectric, LLC for Project No. 13826–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First Street NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3633 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project Nos. 14189–000; 14198–000]

Lock+ Hydro Friends Fund XL; FFP Project 56, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on May 3, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Kentucky River, in Henry County and Owen County, Kentucky. The applications were filed by Lock+ Hydro Friends Fund XL for Project No. 14189–000 and FFP Project 56, LLC for Project No. 14198–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First St. NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3629 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project Nos. 14188–000; 14200–000]

Lock+ Hydro Friends Fund XXVIII; FFP Project 59, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on May 3, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Kentucky River, in Jessamine County and Garrard County, Kentucky. The applications were filed by Lock+ Hydro Friends Fund XXVIII for Project No. 14188–000 and FFP Project 59, LLC for Project No. 14200–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First St. NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3628 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project Nos. 14185–000; 14196–000]

Lock+ Hydro Friends Fund IV; FFP Project 55, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on May 3, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Kentucky River, in Henry County and Owen County, Kentucky. The applications were filed by Lock+ Hydro Friends Fund IV for Project No. 14185–000 and FFP Project 55, LLC for Project No. 14196–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First St. NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3639 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project Nos. 14184–000; 14191–000]

Lock+ Hydro Friends Fund XXXVIII; FFP Project 1, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on May 3, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Arkansas River, in Jefferson County, Arkansas. The applications were filed by Lock+ Hydro Friends Fund XXXVIII for Project No. 14184–000 and FFP Project 1, LLC for Project No. 14191–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First St. NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3638 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 14187–000; Project No. 14199–000]

Lock+ Hydro Friends Fund XXXIV; FFP Project 58, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on May 3, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Kentucky River, in Mercer County and Woodford County, Kentucky. The applications were filed by Lock+ Hydro Friends Fund XXXIV for Project No. 14187–000 and FFP Project 58, LLC for Project No. 14199–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First St. NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3627 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 14186–000; Project No. 14197–000]

Lock+ Hydro Friends Fund XXXV; FFP Project 57, LLC; Notice Announcing Preliminary Permit Drawing

The Commission has received two preliminary permit applications deemed filed on May 3, 2011, at 8:30 a.m.,[1] for proposed projects to be located on the Kentucky River, in Franklin County, Kentucky. The applications were filed by Lock+ Hydro Friends Fund XXXV for Project No. 14186–000 and FFP Project 57, LLC for Project No. 14197–000.

On February 22, 2012, at 9 a.m. (Eastern Time), the Secretary of the Commission, or her designee, will conduct a random drawing to determine the filing priority of the applicants identified in this notice. The Commission will select among competing permit applications as provided in section 4.37 of its regulations.[2] The priority established by this drawing will be used to determine which applicant, among those with identical filing times, will be considered to have the first-filed application.

The drawing is open to the public and will be held in room 2C, the Commission Meeting Room, located at 888 First St. NE., Washington, DC 20426. A subsequent notice will be issued by the Secretary announcing the results of the drawing.

Dated: February 10, 2012.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2012–3626 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

[1] Under the Commission's Rules of Practice and Procedure, any document received after regular business hours is considered filed at 8:30 a.m. on the next regular business day. 18 CFR 385.2001(a)(2) (2011).

[2] 18 CFR 4.37 (2011).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP12–52–000]

Southwest Gas Storage Company; Notice of Request Under Blanket Authorization

Take notice that on January 31, 2012, Southwest Gas Storage Company (Southwest), P.O. Box 4967, Houston, Texas 77210, filed a prior notice application pursuant to sections 157.205, 157.208, 157.213, and 157.216 of the Federal Energy Regulatory Commission's regulations under the Natural Gas Act (NGA), and Southwest's blanket certificate issued in Docket No. CP99–230–000, to construct, replace, and abandon facilities at Southwest's Howell storage field in Livingston County, Michigan. Specifically, Southwest proposes to (1) drill dual horizontal wellbore extensions in two injection/withdrawal wells; (2) convert three injection/withdrawal wells to observation wells; (3) replace pipe associated with four storage laterals; and (4) abandon in place three storage laterals, all as more fully set forth in the application, which is open to the public for inspection. The filing may also be viewed on the web at *http://www.ferc.gov* using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. For assistance, contact FERC at *FERCOnlineSupport@ferc.gov* or call toll-free, (866) 208–3676 or TTY, (202) 502–8659.

Any questions regarding this application should be directed to Stephen Veatch, Senior Director of Certificates and Tariffs, Southwest Gas Storage Company, 501 Westheimer Road, Houston, Texas 77056 or telephone (713) 989–2024 or fax (713) 989–1158 or by email *stephen.veatch@sug.com.*

Any person may, within 60 days after the issuance of the instant notice by the Commission, file pursuant to Rule 214 of the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention. Any person filing to intervene or the Commission's staff may, pursuant to section 157.205 of the Commission's Regulations under the NGA (18 CFR 157.205) file a protest to the request. If no protest is filed within the time allowed therefore, the proposed activity shall be deemed to be authorized effective the day after the time allowed for protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request shall be treated as an application for authorization pursuant to section 7 of the NGA.

Persons who wish to comment only on the environmental review of this project should submit an original and two copies of their comments to the Secretary of the Commission. Environmental commentors will be placed on the Commission's environmental mailing list, will receive copies of the environmental documents, and will be notified of meetings associated with the Commission's environmental review process. Environmental commentors will not be required to serve copies of filed documents on all other parties. However, the non-party commentors will not receive copies of all documents filed by other parties or issued by the Commission (except for the mailing of environmental documents issued by the Commission) and will not have the right to seek court review of the Commission's final order.

The Commission strongly encourages electronic filings of comments, protests, and interventions via the Internet in lieu of paper. See 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site (*www.ferc.gov*) under the ''e-Filing'' link. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

Dated: February 9, 2012.

Kimberly D. Bose,

Secretary.

[FR Doc. 2012–3653 Filed 2–15–12; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OAR–2003–0034; FRL–9633–2]

Agency Information Collection Activities; Proposed Collection; Comment Request; Reporting Requirements Under EPA's Voluntary Aluminum Industrial Partnership (VAIP)

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this document announces that EPA is planning to submit a request to renew an existing approved Information Collection Request (ICR) to the Office of Management and Budget (OMB). This ICR is scheduled to expire on April 30, 2012. Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on specific aspects of the proposed information collection as described below.

DATES: Comments must be submitted on or before April 16, 2012.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2003–0034, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: a-and-r-Docket@epa.gov.*
- *Fax:* 202–566–9744.
- *Mail:* Air and Radiation Docket and Information Center, Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460.
- *Hand Delivery:* EPA Docket Center, Public Reading Room, EPA Headquarters West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2003–0034. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *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 *www.regulations.gov* or email. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means 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 EPA without going through *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, 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 EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, 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. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

FOR FURTHER INFORMATION CONTACT: Sally Rand, Climate Change Division, Office of Atmospheric Programs, 6207J, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: 202–343–9739; fax number: 202–343–2202; email address: *rand.sally@epa.gov.*

SUPPLEMENTARY INFORMATION:

How can I access the docket and/or submit comments?

EPA has established a public docket for this ICR under Docket ID No. EPA–HQ–OAR–2003–0034, which is available for online viewing at *www.regulations.gov,* or in person viewing at the Air and Radiation Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The EPA/DC Public Reading Room is open from 8 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is 202–566–1744, and the telephone number for the Air and Radiation Docket is 202–566–1742.

Use *www.regulations.gov* to obtain a copy of the draft collection of information, submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the docket ID number identified in this document.

What information is EPA particularly interested in?

Pursuant to section 3506(c)(2)(A) of the PRA, EPA specifically solicits comments and information to enable it to:

(i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(iii) enhance the quality, utility, and clarity of the information to be collected; and

(iv) minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses. In particular, EPA is requesting comments from very small businesses (those that employ less than 25) on examples of specific additional efforts that EPA could make to reduce the paperwork burden for very small businesses affected by this collection.

What should I consider when I prepare my comments for EPA?

You may find the following suggestions helpful for preparing your comments:

1. Explain your views as clearly as possible and provide specific examples.
2. Describe any assumptions that you used.
3. Provide copies of any technical information and/or data you used that support your views.
4. If you estimate potential burden or costs, explain how you arrived at the estimate that you provide.
5. Offer alternative ways to improve the collection activity.
6. Make sure to submit your comments by the deadline identified under **DATES**.
7. To ensure proper receipt by EPA, be sure to identify the docket ID number assigned to this action in the subject line on the first page of your response. You may also provide the name, date, and **Federal Register** citation.

What information collection activity or ICR does this apply to?

Docket ID No.: EPA–HQ–OAR–2003–0034.

Affected entities: Entities potentially affected by this action are those engaged in primary aluminum production.

Title: Reporting Requirements under the Voluntary Aluminum Industrial Partnership (VAIP).

ICR numbers: EPA ICR No. 1867.05, OMB Control No. 2060–0411.

ICR status: This ICR is currently scheduled to expire on April 30, 2012. 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 in title 40 of the CFR, after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, are displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: EPA's Voluntary Aluminum Industrial Partnership (VAIP) was initiated in 1995 and is an important voluntary program contributing to the overall reduction in emissions of greenhouse gases. This program focuses on reducing direct greenhouse gas emissions including perfluorocarbon (PFC) and carbon dioxide (CO_2) emissions from the production of primary aluminum. Seven of the eight U.S. producers of primary aluminum participate in this program. PFCs are very potent greenhouse gases with global warming potentials several thousand times that of carbon dioxide and they persist in the atmosphere for thousands of years. CO_2 is emitted from consumption of the carbon anode. EPA has developed this ICR to renew authorization to collect information from companies in the VAIP. Participants voluntarily agree to the following: Designate a VAIP liaison; set emission reduction goals, undertake technically feasible and cost-effective actions to reduce PFC and direct CO_2 emissions, and share information on best practices to reduce emissions. The information is used by EPA to support the sector-wide adoption of cost-effective technically feasible greenhouse gas emissions and assess the success of the program in achieving its goals.

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 30.0 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 training systems for the purposes of collecting, validating, and verifying emission reduction information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements which have subsequently changed; train personnel to be able to respond to emission reduction information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

The ICR provides a detailed explanation of the Agency's estimate, which is only briefly summarized here:

Estimated total number of potential respondents: 7

Frequency of response: Annual.

Estimated total average number of responses for each respondent: One per respondent per year.

Estimated total annual burden hours: 30 hours.

Estimated total annual costs: $10,000. This includes an estimated burden cost of $10,000 and an estimated cost of $0 for capital investment or maintenance and operational costs.

Are there changes in the estimates from the last approval?

There is a decrease of 60 hours in the total estimated respondent burden compared with that identified in the ICR currently approved by OMB. This decrease reflects that effective in 2010, all producers of primary aluminum are subject to mandatory reporting under EPA's Greenhouse Gas Reporting Program (GGRP). Emissions data collection and reporting efforts are no longer components of the voluntary activities covered by this information collection request. Consequently, the overall burden has decreased from 90 hours to 30 hours with the corresponding decrease in the previously estimated reporting burden.

What is the next step in the process for this ICR?

EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval pursuant to 5 CFR 1320.12. At that time, EPA will issue another **Federal Register** notice pursuant to 5 CFR 1320.5(a)(1)(iv) to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB. If you have any questions about this ICR or the approval process, please contact the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

Dated: February 10, 2012.

Rona Birnbaum,

Acting Director, Climate Change Division.

[FR Doc. 2012–3688 Filed 2–15–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–SFUND–2005–0008, FRL–9631–9]

Agency Information Collection Activities; Proposed Collection; Comment Request; Emergency Planning and Release Notification Requirements Under Emergency Planning and Community Right-To-Know Act Sections 302, 303, and 304; EPA ICR No. 1395.08

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this document announces that EPA is planning to submit a request to renew an existing approved Information Collection Request (ICR) to the Office of Management and Budget (OMB). This ICR is scheduled to expire on July 31, 2012. Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on specific aspects of the proposed information collection as described below.

DATES: Comments must be submitted on or before April 16, 2012.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–SFUND–2005–0008 by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Email: superfund.docket@epa.gov.*
- *Fax:* (202) 566–0224.
- *Mail:* Superfund Docket, Environmental Protection Agency, Mailcode: 28221T, 1200 Pennsylvania Ave. NW., Washington, DC 20460.
- *Hand Delivery:* Docket Center, EPA West Bldg., Room 3334, 1301 Constitution Avenue NW., Washington DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–SFUND–2005–0008. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *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 *www.regulations.gov* or email. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means 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 EPA without going through *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, 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 EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, 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. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

FOR FURTHER INFORMATION CONTACT: Sicy Jacob, Office of Emergency Management, Mail Code 5104A, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 564–8019; fax number: (202) 564–2620; email address: *jacob.sicy@epa.gov.*

SUPPLEMENTARY INFORMATION:

How can I access the docket and/or submit comments?

EPA has established a public docket for this ICR under Docket ID No. EPA–HQ–SFUND–2005–0008, which is available for online viewing at *www.regulations.gov,* or in person viewing at the Superfund Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The EPA/DC 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 Reading Room is 202–566–1744, and the telephone number for the Superfund Docket is 202–566–1744.

Use *www.regulations.gov* to obtain a copy of the draft collection of information, submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the docket ID number identified in this document.

What information is EPA particularly interested in?

Pursuant to section 3506(c)(2)(A) of the PRA, EPA specifically solicits comments and information to enable it to:

1. Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;
2. Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
3. Enhance the quality, utility, and clarity of the information to be collected; and
4. Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses. In particular, EPA is requesting comments from very small businesses (those that employ less than 25) on examples of specific additional efforts that EPA could make to reduce the paperwork burden for very small businesses affected by this collection.

What should I consider when I prepare my comments for EPA?

You may find the following suggestions helpful for preparing your comments:

1. Explain your views as clearly as possible and provide specific examples.
2. Describe any assumptions that you used.
3. Provide copies of any technical information and/or data you used that support your views.
4. If you estimate potential burden or costs, explain how you arrived at the estimate that you provide.
5. Offer alternative ways to improve the collection activity.
6. Make sure to submit your comments by the deadline identified under DATES.
7. To ensure proper receipt by EPA, be sure to identify the docket ID number assigned to this action in the subject line on the first page of your response. You may also provide the name, date, and **Federal Register** citation.

What information collection activity or ICR does this apply to?

Docket ID No.: EPA–HQ–SFUND–2005–0008.

Affected entities: Entities potentially affected by this action are those which have a threshold planning quantity of an extremely hazardous substance (EHS) listed in 40 CFR part 355, Appendix A and those which have a release of any of the EHS above a reportable quantity. Entities more likely to be affected by this action may include chemical manufacturers, non-chemical manufacturers, retailers, petroleum refineries, utilities, *etc.*

Title: Emergency Planning and Release Notification Requirements under Emergency Planning and Community Right-to-Know Act Sections 302, 303, and 304.

ICR number: EPA ICR No. 1395.08, OMB Control No. 2050–0092.

ICR status: This ICR is currently scheduled to expire on July 31, 2012. 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 in title 40 of the CFR, after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, are displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: The authority for these requirements is sections 302, 303, and 304 of the Emergency Planning and Community Right-to-Know Act (EPCRA), 1986 (42 U.S.C. 11002, 11003, and 11004). EPCRA established broad emergency planning and facility reporting requirements. Section 302 requires facilities to notify their state emergency response commission (SERC) that the facility is subject to emergency planning. This activity has been completed; this ICR covers only new facilities that are subject to this requirement. Section 303 requires the local emergency planning committees (LEPCs) to prepare emergency plans for facilities that are subject to section 302. This activity has been also completed; this ICR only covers any updates needed for these emergency response plans. Section 304 requires facilities to report to SERCs and LEPCs releases in excess of the reportable quantities listed for each extremely hazardous substance (EHS). This ICR also covers the notification and the written follow-up required under this section. The implementing regulations and the list of substances for emergency planning and emergency release notification are codified in 40 CFR part 355.

On November 3, 2008 (73 FR 64452), EPA has revised some of the requirements in 40 CFR part 355, specifically, the requirements related to emergency planning notification. EPA is now requiring facilities to notify their LEPC within 30 days of any changes occurring at the facility that may be relevant to emergency planning. This revision should not impose any additional burden on facilities subject to emergency planning. Prior to the November 3, 2008 final rule, facilities were required to provide any changes to the LEPC promptly. This final rule now requires facilities to provide any changes within 30 days. Other revisions finalized on November 3, 2008 do not impose any burden on facilities subject to Section 302 and 304 requirements.

Burden Statement: The burden and costs stated below are from the current approved ICR. The average reporting burden for a limited number of existing facilities, to inform the LEPC of any changes at the facility that may affect emergency planning (2.0 hours). The average burden for providing information to the LEPC to develop or update emergency response plans is 11.0 hours. The average reporting burden for facilities reporting releases under 40 CFR 355.40 is estimated to average approximately 9.0 hours per release, including the time for determining if the release is a reportable quantity, notifying the LEPC and SERC, or the 911 operator, and developing and submitting a written follow-up notice. There are no record keeping requirements for facilities under EPCRA Sections 302–304. The total annual burden to facilities is 188,900 hours at a cost of $8.7 million.

The average burden for emergency planning activities is 21 hours per plan for LEPCs, and 16 hours per plan for SERCs. Each SERC and LEPC is also estimated to incur an annual record keeping burden of 10 hours. The total annual burden to LEPCs and SERCs is 106,856 hours at a cost of $4.2 million.

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 which have subsequently changed; 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.

The ICR provides a detailed explanation of the Agency's estimate, which is only briefly summarized here:

Estimated total number of potential respondents: 98,456.

Frequency of response: Occasionally.

Estimated total average number of responses for each respondent: once.

Estimated total annual burden hours: 295,756.

Estimated total annual costs: $68,719 includes annualized capital or O&M costs.

What is the next step in the process for this ICR?

EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval pursuant to 5 CFR 1320.12. At that time, EPA will issue another **Federal Register** notice pursuant to 5 CFR 1320.5(a)(1)(iv) to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB. If you have any questions about this ICR or the approval process, please contact the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

Dated: February 8, 2012.

R. Craig Matthiessen,

Acting Director, Office of Emergency Management.

[FR Doc. 2012–3669 Filed 2–15–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OAR–2003–0052; FRL–9632–1]

Agency Information Collection Activities; Proposed Collection; Comment Request; Risk Management Program Requirements and Petitions To Modify the List of Regulated Substances Under Section 112(r) of the Clean Air Act (CAA)

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this document announces that EPA is planning to submit a request to renew an existing approved Information Collection Request (ICR) to the Office of Management and Budget (OMB). This ICR is scheduled to expire on July 31, 2012. Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on specific aspects of the proposed information collection as described below.

DATES: Comments must be submitted on or before April 16, 2012.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–2003–0052, by one of the following methods:

- *www.regulations.gov*: Follow the on-line instructions for submitting comments.
- *Email: a-and-r-Docket@epa.gov.*
- *Fax:* (202) 566–9744.
- *Mail:* Air Docket, Environmental Protection Agency, Mail code: 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460.
- *Hand Delivery:* Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2003–0052. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *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 *www.regulations.gov* or email. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means 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 EPA without going through *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, 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 EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, 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. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

FOR FURTHER INFORMATION CONTACT: Sicy Jacob, Office of Emergency Management, Mail code 5104A, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 564–8019; fax number: (202) 564–2625; email address: *jacob.sicy@epa.gov.*

SUPPLEMENTARY INFORMATION:

How can I access the docket and/or submit comments?

EPA has established a public docket for this ICR under Docket ID No. EPA–HQ–OAR–2003–0052 which is available for online viewing at *www.regulations.gov*, or in person viewing at the Air Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The EPA/DC 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 Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

Use *www.regulations.gov* to obtain a copy of the draft collection of information, submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the public docket that are available electronically. Once in the system, select ''search,'' then key in the docket ID number identified in this document.

What information is EPA particularly interested in?

Pursuant to section 3506(c)(2)(A) of the PRA, EPA specifically solicits comments and information to enable it to:

(i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(iii) Enhance the quality, utility, and clarity of the information to be collected; and

(iv) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses. In particular, EPA is requesting comments from very small businesses (those that employ less than 25) on examples of specific additional efforts that EPA could make to reduce the paperwork burden for very small businesses affected by this collection.

What should I consider when I prepare my comments for EPA?

You may find the following suggestions helpful for preparing your comments:

1. Explain your views as clearly as possible and provide specific examples.
2. Describe any assumptions that you used.
3. Provide copies of any technical information and/or data you used that support your views.
4. If you estimate potential burden or costs, explain how you arrived at the estimate that you provide.
5. Offer alternative ways to improve the collection activity.
6. Make sure to submit your comments by the deadline identified under **DATES**.
7. To ensure proper receipt by EPA, be sure to identify the docket ID number assigned to this action in the subject line on the first page of your response. You may also provide the name, date, and **Federal Register** citation.

What information collection activity or ICR does this apply to?

Docket ID No. EPA–HQ–OAR–2003–0052.

Affected entities: Entities potentially affected by this action are chemical manufacturers, petroleum refineries, water treatment systems, non-chemical manufacturers, etc.

Title: Risk Management Program Requirements and Petitions to Modify the List of Regulated Substances under Section 112(r) of the Clean Air Act.

ICR number: EPA ICR No. 1656.14, OMB Control No. 2050–0144.

ICR status: This ICR is currently scheduled to expire on July 31, 2012. 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 in title 40 of the CFR, after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, and are displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: The 1990 CAA Amendments added section 112(r) to provide for the prevention and mitigation of accidental releases. Section 112(r) mandates that EPA promulgate a list of ''regulated substances'' with threshold quantities and establish procedures for the addition and deletion of substances from the list of regulated substances. Processes at stationary sources that contain more than a threshold quantity of a regulated substance are subject to accidental release prevention regulations promulgated under CAA section 112(r)(7). These two rules are codified as 40 CFR part 68. Part 68 requires that sources with more than a threshold quantity of a regulated substance in a process develop and implement a risk management program and submit a risk management plan to EPA. The compliance schedule for the part 68 requirements was established by rule on June 20, 1996. The burden to sources that are currently covered by part 68, for initial rule compliance, including rule familiarization and program implementation was accounted for in previous ICRs. Sources submitted their first RMPs on June 21, 1999. For most sources, the next compliance deadlines occurred thereafter at 5 year intervals—on June 21, 2004, and subsequently on June 21, 2009. Some sources revised and submitted their RMPs between the five-year deadlines. These sources were then assigned a new five-year compliance deadline based on the date of their most recent revised plan submission. The next submission deadline of RMPs for most sources is June 21, 2014. However, as only some regulated entities have a compliance deadline of June 2014, the remaining sources have been assigned a deadline in 2013, 2015, 2016 or 2017 (the last two years are after the period covered by this ICR) based on the date of their most recent submission. The period covered by this ICR includes the regulatory reporting deadline, June 2014. In this ICR, EPA has accounted for burden for new sources that may become subject to the regulations, currently covered sources with compliance deadlines in this ICR period (2013 to 2015), sources that are out of compliance since the last regulatory deadline but are expected to comply during this ICR period, and sources that have deadlines beyond this ICR period but are required to comply with certain prevention program documentation requirements.

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 in 40 CFR are listed in 40 CFR part 9.

The EPA would like to solicit comments to:

(i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(iii) Enhance the quality, utility, and clarity of the information to be collected; and

(iv) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Burden Statement: The burden and costs stated below are from the current approved ICR. The public reporting burden will depend on the size of the sources complying with 40 CFR part 68 requirements. In this ICR, the public reporting burden for rule familiarization for new sources is estimated to range from 12 to 32 hours per source. The public reporting burden to prepare and submit an RMP for new sources is estimated to range from 8.25 to 33 hours. The public reporting burden for new sources to develop a prevention program is estimated to range from 7 to 188 hours per source. The public reporting burden for those sources that claim CBI is estimated to be 9.5 hours per source. The public reporting burden for currently covered sources to prepare and submit an RMP is estimated to range from 5 to 28 hours. The public record keeping burden to maintain on-site documentation for currently covered sources is estimated to range from 4.5 to 124 hours. The total annual public reporting burden for all sources is 84,729 hours (254,187 hours over three years). The total annual burden estimated for 16 implementing agencies is 9,253 hours (27,759 hours for three years). Therefore, the total annual burden for all sources and states is estimated to be 93,982 hours (281,946 hours for three years).

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 which have subsequently changed; 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.

The ICR provides a detailed explanation of the Agency's estimate, which is only briefly summarized here:

Estimated total number of potential respondents: 4,589 for this ICR period.

Frequency of response: Every five years, unless the facilities need to update their previous submission earlier to comply with a rule requirement.

Estimated total average number of responses for each respondent: One.

Estimated total annual burden hours: 93,982 Hours including burden for implementing agencies.

Estimated total annual costs: $9,785,371.00. There are no capital or operating and maintenance costs associated with this ICR since all sources are required to submit RMPs on-line using the electronic reporting system, RMP*eSubmit.

What is the next step in the process for this ICR?

EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval pursuant to 5 CFR 1320.12. At that time, EPA will issue another **Federal Register** notice pursuant to 5 CFR 1320.5(a)(1)(iv) to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB. If you have any questions about this ICR or the approval process, please contact the technical person listed under **FOR FURTHER INFORMATION CONTACT**.

Dated: February 8, 2012.

R. Craig Matthiessen,

Acting Director, Office of Emergency Management.

[FR Doc. 2012–3694 Filed 2–15–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9633–1]

California State Motor Vehicle and Nonroad Engine Pollution Control Standards; Truck Idling Requirements; Notice of Decision

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of Decision.

SUMMARY: EPA has granted the California Air Resources Board (CARB) its request for a waiver of preemption and authorization to adopt and enforce California's Truck Idling Requirements. CARB's Truck Idling Requirements apply to new California-certified 2008 and subsequent model year heavy-duty diesel engines in heavy-duty diesel vehicles with a gross vehicle weight rating over 14,000 pounds, and to in-use diesel-fueled commercial vehicles with gross vehicle weight ratings over 10,000 pounds that are equipped with sleeper berths.

DATES: Petitions for review must be filed by April 16, 2012.

ADDRESSES: EPA has established a docket for this action under Docket ID EPA–HQ–OAR–2010–0317. All documents relied upon in making this decision, including those submitted to EPA by CARB, and public comments, are contained in the public docket. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the Air and Radiation Docket in the EPA Headquarters Library, EPA West Building, Room 3334, located at 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room is open to the public on all federal government working days from 8:30 a.m. to 4:30 p.m.; generally, it is open Monday through Friday, excluding holidays. The telephone number for the Reading Room is (202) 566–1744. The Air and Radiation Docket and Information Center's Web site is *http://www.epa.gov/oar/docket.html.* The electronic mail (email) address for the Air and Radiation Docket is: *a-and-r-Docket@epa.gov,* the telephone number is (202) 566–1742, and the fax number is (202) 566–9744. An electronic version of the public docket is available through the federal government's electronic public docket and comment system. You may access EPA dockets at *http://www.regulations.gov.* After opening the *www.regulations.gov* Web site, enter EPA–HQ–OAR–2010–0317 in the ''Enter Keyword or ID'' fill-in box to view documents in the record. Although a part of the official docket, the public docket does not include Confidential Business Information (''CBI'') or other information whose disclosure is restricted by statute.

EPA's Office of Transportation and Air Quality (''OTAQ'') maintains a Web page that contains general information on its review of California waiver requests. Included on that page are links to prior waiver **Federal Register** notices, some of which are cited in today's notice; the page can be accessed at *http://www.epa.gov/otaq/cafr.htm.*

FOR FURTHER INFORMATION CONTACT: Kristien G. Knapp, Attorney-Advisor, Compliance and Innovative Strategies Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue (6405J), NW., Washington, DC 20460. Telephone: (202) 343–9949. Fax: (202) 343–2800. Email: *knapp.kristien@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

A. California's Truck Idling Requirements

By letter dated May 9, 2008, CARB informed EPA that it had adopted its Truck Idling Requirements, and requested that EPA confirm that certain provisions of the requirements are not preempted by sections 209(a) of the Clean Air Act (Act); certain provisions are conditions precedent pursuant to section 209(a) of the Act; [1] certain provisions are within-the-scope of previous waivers and authorizations issued pursuant to sections 209(b) and 209(e) of the Act, respectively; and at least one provision requires and merits a full authorization pursuant to section 209(e) of the Act.[2] CARB's 2008 Truck Idling Requirements became effective California state law on November 15, 2006, amending title 13, California Code of Regulations (CCR) sections 1956.8, 2404, 2424, 2425, and 2485.[3]

CARB's Truck Idling Requirements consist of three elements: (1) ''New engine requirements'' that require new California-certified 2008 and subsequent model year on-road diesel engines in vehicles with a gross vehicle weight rating (GVWR) greater than 14,000 pounds (*i.e.,* heavy-duty diesel vehicles or ''HDDV''s) be equipped with a system that automatically shuts down the engine after five minutes of continuous idling; (2) ''sleeper truck requirements'' that require the operator of a sleeper truck to manually shut down the engine after five minutes of continuous idling;

[1] EPA can confirm that a California requirement is a condition precedent to sale, titling, or registration, if: (1) the requirements do not constitute new or different standards or accompanying enforcement procedures, and (2) the requirements do not affect the basis for the previous waiver decision.

[2] California Air Resources Board (CARB) Letter to EPA regarding, ''Requirements to Reduce Idling Emissions From New and In-Use Trucks, Beginning in 2008; Request for Confirmation That Certain Requirements are not Subject to Preemption Under Clean Air Act Section 209(a) or Fall Within the Scope of Previously Granted Waivers and Authorizations, and Request for New Authorization Under Section 209(e)(2),'' EPA–HQ–OAR–2010–0317–0001.

[3] *See* California Air Resources Board (CARB), ''Final Regulation Order,'' EPA–HQ–OAR–2010–0317–0011.

and (3) ''alternative technology requirements'' that establish in-use performance standards for HDDV operators who use alternative technologies to supply power for truck cab or sleeper berth climate control and/or other on-board accessories that otherwise would have been generated by the continuous idling of the truck's main engine.[4] CARB requests, first, that EPA confirm that its new engine requirements are not preempted by section 209(a) of the Act, or that they are other conditions precedent required prior to the initial sale of new heavy-duty diesel engines. Alternatively, CARB requests that if EPA concludes that the new engine requirements are preempted by section 209(a) of the Act, then EPA confirm that the requirements are within the scope of EPA's previously issued waiver for 2007 and later model year heavy-duty diesel engines. Second, CARB requests that EPA confirm that its sleeper truck requirements are purely operational controls, which are not preempted by section 209(a) of the Act. Third, CARB requests the following determinations from EPA with respect to its alternative technology requirements: (1) A within-the-scope confirmation for its requirement that an alternative power supply (APS) may only be operated if that engine has been certified to meet either applicable California off-road or federal nonroad emission standards and test procedures for its fuel type and power category;[5] (2) a full authorization for its requirement that a driver may not operate a diesel-fueled APS engine on a vehicle with a primary engine certified to the 2007 and subsequent model year standards unless the APS is certified to meet the applicable California or federal standard and meets one of three additional requirements;[6] and (3) a determination that its requirements pertaining to fuel-fired heaters, batteries, fuel cells, and power inverter/chargers for on-shore power are not preempted by section 209.

B. Clean Air Act New Motor Vehicle Waivers of Preemption

Section 209(a) of the Clean Air Act preempts states and local governments from setting emission standards for new motor vehicles and engines; it provides:

> No State or any political subdivision thereof shall adopt or attempt to enforce any standard relating to the control of emissions from new motor vehicles or new motor vehicle engines subject to this part. No state shall require certification, inspection or any other approval relating to the control of emissions from any new motor vehicle or new motor vehicle engine as condition precedent to the initial retail sale, titling (if any), or registration of such motor vehicle, motor vehicle engine, or equipment.

Through operation of section 209(b) of the Act, California is able to seek and receive a waiver of section 209(a)'s preemption. If certain criteria are met, section 209(b)(1) of the Act requires the Administrator, after notice and opportunity for public hearing, to waive application of the prohibitions of section 209(a). Section 209(b)(1) only allows a waiver to be granted for any State that had adopted standards (other than crankcase emission standards) for the control of emissions from new motor vehicles or new motor vehicle engines prior to March 30, 1966, if the State determines that its standards will be, in the aggregate, at least as protective of public health and welfare as applicable federal standards (*i.e.,* if such State makes a ''protectiveness determination''). Because California was the only state to have adopted standards prior to 1966, it is the only state that is qualified to seek and receive a waiver.[7] The Administrator must grant a waiver unless she finds that: (A) California's above-noted ''protectiveness determination'' is arbitrary and capricious;[8] (B) California does not need such State standards to meet compelling and extraordinary conditions;[9] or (C) California's standards and accompanying enforcement procedures are not consistent with section 202(a) of the Act.[10] EPA has previously stated that consistency with section 202(a) requires that California's standards must be technologically feasible within the lead time provided, giving due consideration of costs, and that California and applicable federal test procedures be consistent.[11]

The second sentence of section 209(a) of the Act prevents states from requiring, ''certification, inspection or any other approval relating to the control of emissions from any new motor vehicle or new motor vehicle engine as condition precedent to the initial retail sale, titling (if any), or registration of such motor vehicle, motor vehicle engine, or equipment.'' However, once EPA has granted California a waiver of section 209(a)'s preemption for emission standards and/or accompanying enforcement procedures, California may then require other such conditions precedent.[12] EPA can confirm that a California requirement is a condition precedent to sale, titling, or registration, if: (1) The requirements do not constitute new or different standards or accompanying enforcement procedures, and (2) the requirements do not affect the basis for the previous waiver decision.

In contrast to section 209(a)'s preemption of state adoption of standards controlling emissions from new motor vehicles and motor vehicle engines, section 209(d) of the Act explicitly preserves states' ability to regulate vehicles and engines in use. Section 209(d) provides that despite section 209(a)'s preemption, ''Nothing in this part shall preclude or deny to any State or political subdivision thereof the right otherwise to control, regulate, or restrict the use, operation, or movement of registered or licensed motor vehicles.''[13]

C. Clean Air Act Nonroad Engine and Vehicle Authorizations

Section 209(e)(1) of the Act permanently preempts any State, or political subdivision thereof, from adopting or attempting to enforce any standard or other requirement relating to the control of emissions for certain new nonroad engines or vehicles. Section 209(e)(2) of the Act requires the Administrator to grant California authorization to enforce its own

[4] *See* California Air Resources Board (CARB), ''Waiver and Authorization Action Support Document,'' pp. 1–13, EPA–HQ–OAR–2010–0317–0002 (hereinafter ''CARB Support Document'').

[5] CARB believes this requirement is within-the-scope of the previous authorization for new nonroad engine standards because that authorization already allows enforcement of California's requirement that any new APS engine acquired since the 2000 model year is required to meet the California or federal nonroad engine emission standards. *See* 75 FR 8056 (February 23, 2010).

[6] The additional requirements are one of the following: (a) Exhaust routed into the truck's exhaust system and PM trap; (b) a level 3 verified PM control strategy; or (c) use of other procedures to demonstrate an equivalent level of emissions compliance.

[7] *See* S.Rep. No. 90–403 at 632 (1967).

[8] CAA section 209(b)(1)(A).

[9] CAA section 209(b)(1)(B).

[10] CAA section 209(b)(1)(C).

[11] *See, e.g.,* 74 FR 32767 (July 8, 2009); *see also* Motor and *Equipment Manufacturers Association* v. *EPA* (*MEMA I*), 627 F.2d 1095, 1126 (D.C. Cir. 1979).

[12] ''Once California receives a waiver for standards for a certain class of motor vehicles, it need only meet the waiver criteria of section 209(b) for regulations pertaining to those vehicles when it adopts new or different standards or accompanying enforcement procedures. Otherwise, California may adopt any other condition precedent to the initial retail sale, titling, or registration of those vehicles without the necessity of receiving a further waiver of Federal preemption.'' 43 FR 36680 (August 18, 1978).

[13] *See also Engine Mfrs. Ass'n* v. *EPA,* 88 F.3d 1075, 1094 (D.C. Cir. 1996).

standards for new nonroad engines or vehicles, which are not listed under section 209(e)(1), subject to certain restrictions. On July 20, 1994, EPA promulgated a rule that sets forth, among other things, the criteria, as found in section 209(e)(2), which EPA must consider before granting any California authorization request for new nonroad engine or vehicle emission standards. On October 8, 2008, the regulations promulgated in that rule were moved to 40 CFR Part 1074, and modified slightly.[14] As stated in the preamble to the section 209(e) rule, EPA has historically interpreted the section 209(e)(2)(iii) ''consistency'' inquiry to require, at minimum, that California standards and enforcement procedures be consistent with section 209(a), section 209(e)(1), and section 209(b)(1)(C) (as EPA has interpreted that subsection in the context of section 209(b) motor vehicle waivers).[15]

In order to be consistent with section 209(a), California's nonroad standards and enforcement procedures must not apply to new motor vehicles or new motor vehicle engines. To be consistent with section 209(e)(1), California's nonroad standards and enforcement procedures must not attempt to regulate engine categories that are permanently preempted from state regulation. To determine consistency with section 209(b)(1)(C), EPA typically reviews nonroad authorization requests under the same ''consistency'' criteria that are applied to motor vehicle waiver requests. Pursuant to section 209(b)(1)(C), the Administrator shall not grant California a motor vehicle waiver if she finds that California ''standards and accompanying enforcement procedures are not consistent with section 202(a)'' of the Act. Previous decisions granting waivers and authorizations have noted that state standards and enforcement procedures are inconsistent with section 202(a) if: (1) There is inadequate lead time to permit the development of the necessary technology giving appropriate consideration to the cost of compliance within that time, or (2) the federal and state testing procedures impose inconsistent certification requirements.

D. Within-the-Scope Determinations

If California amends regulations that were previously granted a waiver of preemption, EPA can confirm that the amended regulations are within the scope of the previously granted waiver. Such within-the-scope amendments are permissible without a full waiver review if three conditions are met. First, the amended regulations must not undermine California's determination that its standards, in the aggregate, are as protective of public health and welfare as applicable federal standards. Second, the amended regulations must not affect consistency with section 202(a) of the Act. Third, the amended regulations must not raise any ''new issues'' affecting EPA's prior waivers.

E. Burden of Proof

In *Motor and Equip. Mfrs Assoc.* v. *EPA,* 627 F.2d 1095 (DC Cir. 1979) (''*MEMA I''*), the U.S. Court of Appeals stated that the Administrator's role in a section 209 proceeding is to:

> consider all evidence that passes the threshold test of materiality and * * * thereafter assess such material evidence against a standard of proof to determine whether the parties favoring a denial of the waiver have shown that the factual circumstances exist in which Congress intended a denial of the waiver.[16]

The court in *MEMA I* considered the standards of proof under section 209 for the two findings related to granting a waiver for an ''accompanying enforcement procedure'' (as opposed to the standards themselves): (1) Protectiveness in the aggregate and (2) consistency with section 202(a) findings. The court instructed that ''the standard of proof must take account of the nature of the risk of error involved in any given decision, and it therefore varies with the finding involved. We need not decide how this standard operates in every waiver decision.'' [17]

The court upheld the Administrator's position that, to deny a waiver, there must be 'clear and compelling evidence' to show that proposed procedures undermine the protectiveness of California's standards.[18] The court noted that this standard of proof also accords with the congressional intent to provide California with the broadest possible discretion in setting regulations it finds protective of the public health and welfare.[19]

With respect to the consistency finding, the court did not articulate a standard of proof applicable to all proceedings, but found that the opponents of the waiver were unable to meet their burden of proof even if the standard were a mere preponderance of the evidence. Although *MEMA I* did not explicitly consider the standards of proof under section 209 concerning a waiver request for ''standards,'' as compared to accompanying enforcement procedures, there is nothing in the opinion to suggest that the court's analysis would not apply with equal force to such determinations. EPA's past waiver decisions have consistently made clear that: ''[E]ven in the two areas concededly reserved for Federal judgment by this legislation—the existence of 'compelling and extraordinary' conditions and whether the standards are technologically feasible—Congress intended that the standards of EPA review of the State decision to be a narrow one.'' [20]

Opponents of the waiver bear the burden of showing that the criteria for a denial of California's waiver request have been met. As found in *MEMA I,* this obligation rests firmly with opponents of the waiver in a section 209 proceeding:

> [t]he language of the statute and its legislative history indicate that California's regulations, and California's determinations that they must comply with the statute, when presented to the Administrator are presumed to satisfy the waiver requirements and that the burden of proving otherwise is on whoever attacks them. California must present its regulations and findings at the hearing and thereafter the parties opposing the waiver request bear the burden of persuading the Administrator that the waiver request should be denied.[21]

The Administrator's burden, on the other hand, is to make a reasonable evaluation of the information in the record in coming to the waiver decision. As the court in *MEMA I* stated: ''here, too, if the Administrator ignores evidence demonstrating that the waiver should not be granted, or if he seeks to overcome that evidence with unsupported assumptions of his own, he runs the risk of having his waiver

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[14] The applicable regulations, now in 40 CFR part 1074, subpart B, § 1074.105, provide:

(a) The Administrator will grant the authorization if California determines that its standards will be, in the aggregate, at least as protective of public health and welfare as otherwise applicable federal standards.

(b) The authorization will not be granted if the Administrator finds that any of the following are true:

(1) California's determination is arbitrary and capricious.

(2) California does not need such standards to meet compelling and extraordinary conditions.

(3) The California standards and accompanying enforcement procedures are not consistent with section 209 of the Act.

(c) In considering any request from California to authorize the state to adopt or enforce standards or other requirements relating to the control of emissions from new nonroad spark-ignition engines smaller than 50 horsepower, the Administrator will give appropriate consideration to safety factors (including the potential increased risk of burn or fire) associated with compliance with the California standard.

[15] *See* 59 FR 36969 (July 20, 1994).

[16] *MEMA I,* 627 F.2d at 1122.

[17] *Id.*

[18] *Id.*

[19] *Id.*

[20] *See, e.g.,* 40 FR 21102–103 (May 28, 1975).

[21] *MEMA I,* 627 F.2d at 1121.

decision set aside as 'arbitrary and capricious.''' [22] Therefore, the Administrator's burden is to act ''reasonably.'' [23]

F. EPA's Administrative Process in Consideration of California's Truck Idling Requirements

Upon review of CARB's request, EPA invited public comment on the entire request, including but not limited to the following issues.

First, we asked whether we should consider CARB's new engine requirements as non-preempted operational controls, or as conditions precedent. In the alternative, should we determine that CARB's new engine requirements must be treated as standards relating to the control of emissions or accompanying enforcement procedures, we asked whether they be subject to and meet the criteria for EPA to confirm that they are within-the-scope of EPA's waiver for new heavy-duty diesel engines for 2007 and subsequent model years. To the extent the new engine requirements should be treated as standards relating to the control of emissions or accompanying enforcement procedures and require a full waiver from EPA, we asked whether the requirements meet the full waiver criteria.

Second, we asked whether CARB's sleeper truck requirements properly should be considered an operational control and thus not preempted by section 209 of the Act. To the extent that CARB's sleeper truck requirements should be treated as standards relating to the control of emissions from new motor vehicles or engines or accompanying enforcement procedures and require a full waiver from EPA, we sought comment on whether the requirements meet the criteria for a full waiver.

Third, with respect to CARB's alternative technology requirements, EPA sought comment on the following specific questions: (1) Does CARB's requirement that an APS using an internal combustion engine be certified to meet either California off-road or federal nonroad emission standards and test procedures meet the requirements for finding that it is within-the-scope of the authorization EPA issued for new nonroad engine standards, thus not requiring a full authorization?; [24] (2) If not, does CARB's requirement that an APS using an internal combustion engine be certified to meet either California off-road or federal nonroad emission standards and test procedures meet the requirements for a full authorization?; (3) Does CARB's requirement that a diesel-fueled APS engine be certified to the California or federal 2007 and subsequent model year standards and meet one of three other listed requirements [25] meet the criteria for a full authorization?; and (4) Are CARB's requirements pertaining to fuel-fired heaters, batteries, fuel cells, power inverter/chargers for on-shore power, and truck electrification preempted under section 209 of the Clean Air Act, and if so, do they meet the requirements for waiver under section 209(b) or authorization under section 209(e)?

As called out by those specific questions, EPA sought threshold input on whether to treat various elements of CARB's Truck Idling Requirements as conditions precedent, within the scope of previous waivers and authorizations, not preempted by section 209, or in need of a full waiver or authorization. We also sought substantive comment on whether the various elements of CARB's Truck Idling Requirements meet the applicable criteria for confirmation as conditions precedent, within the scope, non-preemption, and full waiver or authorization.

In response to EPA's July 27, 2010 **Federal Register** notice, EPA received three written comments and no request for a public hearing. The written comments are from the American Trucking Associations (''ATA''),[26] the Owner-Operator Independent Drivers Association, Inc. (''OOIDA''),[27] and CARB.[28]

ATA's comments specifically oppose California's ''alternative technology requirements,'' which establish in-use performance standards for HDDV operators who use alternative technologies (e.g., auxiliary power units) to supply power for truck cab or sleeper berth climate control and/or other on-board accessories that otherwise would have been generated by the continuous idling of the truck's main engine. ATA comments that those requirements are not consistent with sections 202(a) and 209(e) of the Clean Air Act.

OOIDA's comments address issues it believes have been overlooked by EPA, including ''CARB's delay in requesting EPA review of Truck Idling Requirements without waiting for an EPA determination; CARB's premature implementation and enforcement of those Requirements without waiting for an EPA determination; and CARB's failure to consider the potential adverse impact of these requirements on the health and welfare of the affected truck drivers.'' OOIDA also suggested that the Truck Idling Requirements may be preempted by federal law other than the Clean Air Act. OOIDA also requested an additional forty-five days—until November 15, 2010—to fully evaluate a recent decision by the United States Court of Appeals for the Ninth Circuit, *Association of American Railroads et. al.* v. *South Coast Air Quality Management District, et. al.,* case number 07–55804.[29] EPA did not formally extend the written comment period pursuant to this request, but did communicate to OOIDA that it would consider any written comments received before the Agency reached its final decision. OOIDA did not submit any further comments prior to EPA's final decision, published here today.

CARB submitted additional information in the form of supplemental comments to update its request in light of EPA's authorization of California's new nonroad compression-ignition regulations, and information regarding technological feasibility. CARB also responded to EPA's request for comments, and the comments EPA received from ATA and OOIDA. CARB's supplemental comments assert that ATA and OOIDA have failed to meet their burden of proof for a denial. CARB further requests that EPA grant California its requested waiver and authorizations to adopt and enforce its Truck Idling Requirements.

II. Discussion

California's Truck Idling Requirements feature four general sets of requirements: Those applicable to

[22] *Id.* at 1126.

[23] *Id.* at 1126.

[24] 75 FR 8056 (February 23, 2010).

[25] The additional requirements are one of the following: (a) Exhaust routed into the truck's exhaust system and PM trap; (b) a level 3 verified PM control strategy; or (c) use of other procedures to demonstrate an equivalent level of emissions compliance.

[26] American Truck Associations (''ATA''), ''Docket ID No. EPA–HQ–OAR–2010–0317,'' September 30, 2010, EPA–HQ–OAR–2010–0317–0017, September 30, 2010 (hereinafter ''ATA Comments'').

[27] Owner-Operator Independent Drivers Association Inc. (''OOIDA''), ''Initial Comments of Owner-Operator Independent Drivers Association & Request for Additional Time to Provide Additional Comments,'' October 1, 2010 (hereinafter ''OOIDA Comments'').

[28] CARB, Additional Information to Support California's Request for Waiver and Authorization Actions for California's 2008 Truck Idling Requirements, and Response to Comments Submitted by Parties Opposing California's Waiver and Authorization Request; Docket ID No. EPA–HQ–2010–0317,'' EPA–HQ–OAR–2010–0317–1109, February 23, 2010 (hereinafter ''CARB Supplemental Comments'').

[29] *Association of American Railroads et. al.* v. *South Coast Air Quality Management District, et. al.,* case number 07–55804 (9th Cir. 2010), *available at http://www.ca9.uscourts.gov/datastore/opinions/2010/09/15/07–55804.pdf.*

new engines, those applicable to sleeper trucks, alternative technology requirements, and labeling requirements.

A. California's New Engine Requirements

The new engine requirements imposed by California's Truck Idling Requirements establish two compliance options for new California certified 2008 and subsequent model year heavy-duty diesel engines installed in trucks with a gross vehicle weight rating greater than 14,000 pounds. The first compliance option requires engine manufacturers to install a system that automatically shuts down the engine after five minutes of continuous idle operation. The second compliance option is an optional NO_X idling emission standard of 30 grams per hour.

CARB presents, first, that the new engine requirements are akin to operational controls on in-use vehicles and, accordingly, they are not preempted by Clean Air Act section 209(b). Alternatively, CARB argues that the new engine requirements are ''other conditions precedent'' to initial sale, titling, or registration that fall within the scope of the waiver of preemption EPA issued for California's 2007 and subsequent model year heavy-duty diesel engine standards. Last, CARB argues that should EPA determine that the new engine requirements constitute standards relating to the control of emissions from new motor vehicle engines, such requirements fall within the scope of previous waivers of preemption. Thus, EPA must first determine what type of control the California new engine requirements impose before proceeding with an analysis of whether California meets the necessary Clean Air Act requirements under section 209.

To address these issues, EPA asked the first set of questions in the July 27, 2010 **Federal Register** notice. We asked whether we should consider CARB's new engine requirements as non-preempted operational controls, or as conditions precedent. In the alternative, we asked if we determine that CARB's new engine requirements must be treated as standards relating to the control of emissions or accompanying enforcement procedures, whether they be subject to and meet the criteria for EPA to confirm that they are within-the-scope of EPA's waiver for new heavy-duty diesel engines for 2007 and subsequent model years. To the extent the new engine requirements should be treated as standards relating to the control of emissions or accompanying enforcement procedures and require a full waiver from EPA, we asked whether the requirements meet the full waiver criteria.

1. Application of Section 209(b) Waiver Criteria

EPA received no comments in response to the issues EPA raised for comment with respect to California's new engine requirements.

Despite CARB's contentions, EPA has determined that California's new engine requirements are standards relating to the control of emissions that require a full waiver of preemption from EPA. CARB believes that the United States Supreme Court's interpretation of ''standard relating to the control of emissions from new motor vehicles or new motor vehicle engines'' in *Engine Manufacturers Association* v. *South Coast Air Quality Management District,* 541 U.S. 246 (2004) supports its position that the California new engine requirements are not standards relating to the control of emissions. To the contrary, EPA believes that the Supreme Court's interpretation supports the conclusion that California's new engine requirements should be considered as standards relating to the control of emissions. The primary compliance option of the new engine requirements requires new 2008 and later model year heavy-duty diesel engines to be equipped with idling shutdown systems. CARB presents that the primary compliance option does not establish a numerical emission standard, and does not require additional emission control devices or design features related to the control of emissions. While it is clear that requiring a shutdown system does not establish a numerical emission standard, it is also clear that requiring manufacturers to design their engines with a shutdown system to control truck idling emissions does impose a requirement upon manufacturers, for the purpose of limiting emissions. Even though this requirement imposes itself as a design requirement and not as an emissions performance standard, it is nevertheless a requirement related to emission reduction. Furthermore, the Supreme Court in *EMA* v. *South Coast* explicitly contemplated that a ''design feature related to the control of emissions'' would be considered a standard relating to the control of emissions. Additionally, California's optional NO_X idling standard, as an alternative compliance option, makes clear what the force and effect of the new engine requirements is—to limit emissions from idling trucks by imposing a requirement on new engines. Thus, EPA has determined that California's new engine requirements are standards relating to the control of emissions; and therefore, EPA has evaluated the new engine requirements by application of the full waiver criteria.

CARB alternatively requested that EPA evaluate California's new engine requirements by application of EPA's within-the-scope criteria. However, the new engine requirements impose an additional design requirement upon engine manufacturers, which is a ''new issue'' and cautions against application of the within-the-scope criteria. CARB believes its requirement that manufacturers include an engine shutdown system does not present a ''new issue'' because it ''will only require manufacturers to perform minor reprogramming of the software incorporated in existing engine or vehicle computers, and will not require any modifications to hardware.'' [30] In contrast, EPA believes that manufacturers existing designs do not factor into our analysis here.[31] EPA views the additional design requirement imposed upon manufacturers as a new regulatory issue, which was not considered in our previous waiver for California's 2007 and subsequent model year heavy-duty diesel standards. Therefore, as stated above, we have applied the full waiver criteria to California's request.

2. California's Protectiveness Determination

Section 209(b)(1)(A) of the Clean Air Act requires EPA to deny a waiver if the Administrator finds that California was arbitrary and capricious in its determination that its State standards will be, in the aggregate, at least as protective of public health and welfare as applicable federal standards. When evaluating California's protectiveness determination, EPA compares the stringency of the California and federal standards at issue in a given waiver request. That comparison is undertaken within the broader context of the previously waived California program, which relies upon protectiveness determinations that EPA previously found were not arbitrary and capricious.

When California adopted its Truck Idling Requirements, the CARB Board made its protectiveness finding in its Resolution 05–55.[32] That protectiveness

[30] CARB Support Document at 31.

[31] Manufacturers current designs and system capabilities are more appropriately evaluated under the CAA section 209(b)(1)(C) technological feasibility criterion.

[32] CARB Resolution 05–55, EPA–HQ–OAR–2010–0008, ''Be It Further Resolved that the Board hereby determines that the regulations adopted herein will

Continued

determination was made against the background of California's previous protectiveness determination for its 2007 and subsequent model year heavy duty diesel standards, which EPA previously found was not arbitrary and capricious.[33] Compared to the federal standards, California's 2007 and subsequent model year heavy-duty diesel standards are numerically equivalent. Furthermore, CARB asserts that it's Truck Idling Requirements ''in no way reduce the stringency of either the underlying exhaust emission standards or the associated test procedures.'' [34] Notably, the new engine requirements California is imposing within its Truck Idling Requirements are an additional requirement beyond that which is required by EPA's federal standards. Thus, CARB presents that EPA has ''no basis for finding that CARB'' made its protectiveness determination arbitrarily or capriciously.[35]

No commenter expressed an opinion or presented any evidence suggesting that CARB was arbitrary and capricious in making its above-noted protectiveness findings. Therefore, based on the record, EPA cannot find that California was arbitrary and capricious in its findings that California's new engine requirements are, in the aggregate, at least as protective of public health and welfare as applicable federal standards.

3. California's Need for State Standards To Meet Compelling and Extraordinary Conditions

Under section 209(b)(1)(B) of the Act, EPA cannot grant a waiver if California ''does not need such State standards to meet compelling and extraordinary conditions.'' To evaluate this criterion, EPA considers whether California needs a separate motor vehicle emissions program to meet compelling and extraordinary conditions.

Over the past forty years, CARB has repeatedly demonstrated the need for its motor vehicle emissions program to address compelling and extraordinary conditions in California.[36] In its Resolution 05–55, CARB affirmed its longstanding position that California continues to need its own motor vehicle and engine program to meet its serious air pollution problems. Likewise, EPA has consistently recognized that California continues to have the same ''geographical and climatic conditions that, when combined with the large numbers and high concentrations of automobiles, create serious pollution problems.'' [37] Furthermore, no commenter has presented any argument or evidence to suggest that California no longer needs a separate motor vehicle emissions program to address compelling and extraordinary conditions in California. Therefore, EPA has determined that we cannot deny California a waiver for its new engine requirements under section 209(b)(1)(B).

4. Consistency With Section 202(a) of the Clean Air Act

Under section 209(b)(1)(C) of the Act, EPA must deny a California waiver request if the Agency finds that California standards and accompanying enforcement procedures are not consistent with section 202(a) of the Act. The scope of EPA's review under this criterion is narrow. EPA has stated on many occasions that the determination is limited to whether those opposed to the waiver have met their burden of establishing that California's standards are technologically infeasible, or that California's test procedures impose requirements inconsistent with federal test procedures. Previous waivers of federal preemption have stated that California's standards are not consistent with section 202(a) if there is inadequate lead time to permit the development of technology necessary to meet those requirements, giving appropriate consideration to the cost of compliance within that time. California's accompanying enforcement procedures would be inconsistent with section 202(a) if the federal and California test procedures conflict, *i.e.,* if manufacturers would be unable to meet both the California and federal test requirements with the same test vehicle.

California presents that its new engine requirements are currently technologically feasible, with appropriate consideration given to cost, and do not impose inconsistent certification requirements.[38] First, CARB presents information regarding the current technological feasibility of the engine shutdown compliance option: ''The technology needed to comply with the new engine shutdown system option presently exists, and in fact has been widely available as a standard feature in most commercially available on-road heavy-duty engines.'' [39] CARB notes that a number of manufacturers already include such technology in their engines, but most fleet owners and operators do not activate it. For manufacturers who did not include such technology in their engines, CARB staff notes that only minor modifications would be needed. The costs associated with modifications, as estimated by CARB staff, are minimal—''$100 per engine to cover additional administrative costs and minimal reprogramming costs.'' [40] Next, CARB presents information regarding the technological feasibility of the optional NO_X idling standard.[41] Significantly, CARB notes that many manufacturers have either already certified to the optional NO_X standard or intend to in future model years. These manufacturers have implemented strategies to meet the optional NO_X idling standard without adding any additional hardware or modifications to their emission control systems or components. Manufacturers have certified to the standard merely by making modifications to their existing software (*e.g.,* by modifying exhaust gas recirculation rates and/or the pulse of the fuel injectors during idle operating modes). Last, CARB presents information regarding the effect of California's new engine requirements on manufacturers' existing certification requirements. CARB asserts that: ''Neither the new engine shutdown system nor the optional NO_X idling emission standard option present any issues of test procedure inconsistency because there are no analogous federal requirements.'' [42] CARB also confirms that manufacturers may conduct one set of tests to determine compliance with both California and federal requirements.[43]

No commenter expressed any disagreement with these statements from CARB, and no commenter presented any evidence opposing CARB's assertions regarding technological feasibility, lead-time, and cost of compliance. Therefore, EPA is unable to find that California's new engine requirements are not technologically feasible within the

not cause California motor vehicle emission standards, in the aggregate, to be less protective of the public health and welfare than applicable federal standards.''

[33] 70 FR 50322 (August 26, 2005).

[34] CARB Support Document at 27.

[35] CARB Supplemental Comments at 6.

[36] *See, e.g.,* Approval and Promulgation of State Implementation Plans; California—South Coast, 64 FR 1770, 1771 (January 12, 1999). *See also* 69 FR 23858, 23881–90 (April 30, 2004) (designating 15 areas in California as nonattainment for the federal 8-hour ozone national ambient air quality standard).

[37] 49 FR 18887, 18890 (May 3, 1984); *see also* 76 FR 34693 (June 14, 2011), 74 FR 32744, 32763 (July 8, 2009), and 73 FR 52042 (September 8, 2008).

[38] CARB Support Document at 27.

[39] CARB Support Document at 28–29.

[40] *Id.* at 28; *see also* CARB, ''Staff Report: Initial Statement of Reasons,'' EPA–HQ–OAR–2010–0317–0005, (hereinafter ''ISOR''), at 37.

[41] CARB Support Document at 30.

[42] CARB Support Document at 31.

[43] *Id.*

available lead-time, giving appropriate consideration to the cost of compliance.

5. Full Waiver of Preemption Determination for California's New Engine Requirements

After a review of the information submitted by CARB and other parties to this proceeding, EPA finds that those opposing California's request have not met the burden of demonstrating that a waiver for California's new engine requirements should be denied based on any of the three statutory criteria of section 209(b)(1). For this reason, EPA finds that California's new engine requirements should receive a full waiver of preemption.

B. California's Sleeper Truck Requirements

California's Truck Idling Requirements impose a new requirement on the operators of sleeper berth equipped heavy-duty diesel vehicles. Sleeper truck operators will now be required to manually shut off engines after five minutes of continuous idling. To address CARB's sleeper truck requirements, EPA asked the second set of questions in the July 27, 2010 **Federal Register** notice. We asked whether CARB's sleeper truck requirements properly should be considered an operational control and thus not preempted by section 209 of the Act. To the extent that CARB's sleeper truck requirements should be treated as standards relating to the control of emissions from new motor vehicles or engines or accompanying enforcement procedures and require a full waiver from EPA, we sought comment on whether the requirements meet the criteria for a full waiver.

1. California's Sleeper Truck Requirements Do Not Require a Waiver From EPA

California asserts that the sleeper truck requirements are an in-use operational control of motor vehicles and do not require a waiver of preemption. Since the sleeper truck requirements only apply to in-use motor vehicles, and Clean Air Act section 209(a) preemption only applies to new motor vehicles and engines, CARB asserts that section 209(a) preemption does not apply to these requirements. Additionally, CARB points towards section 209(d) of the Act, which states: ''Nothing in this part shall preclude or deny to any State or political subdivision thereof the right otherwise to control, regulate, or restrict the use, operation, or movement of registered vehicles.'' Read together, sections 209(a) and 209(d) make clear that operational controls, such as idling limits directed towards the operator of the vehicle, are not preempted and do not need a waiver of preemption pursuant to section 209(b). EPA agrees with this analysis and does not believe that in-use controls, such as idling limits, are preempted by section 209(a). Therefore, California's sleeper truck requirements do not require a waiver of preemption under section 209(b) of the Act.

2. Other Issues

OOIDA comments that the sleeper truck idling requirements will have an adverse effect on the health and welfare of drivers. This comment is inapplicable to EPA's analysis here, because as stated above, EPA has found that the sleeper truck requirements are not preempted under section 209(a). Therefore, EPA has no authority to evaluate California's sleeper truck requirements. To the extent this comment suggests that California's protectiveness determination for its alternative technology requirements was arbitrary and capricious, we have addressed that issue below.

C. California's Alternative Technology Requirements

CARB anticipated that truck operators would likely utilize alternative technologies to power truck cabins, sleeper berths, and/or other on-board accessories that previously would have been powered by the truck's main engine. Such alternative technologies include internal combustion engine powered alternative power sources (''APSs'') and fuel-fired heaters. To account for the increased particulate matter (PM) emissions that would be generated by inclusion of these alternative technologies on heavy-duty diesel vehicles, CARB developed alternative technology requirements. CARB's general alternative technology requirement is that internal combustion engines used in APSs must be certified to the California or federal nonroad emission standards and test procedures applicable to the fuel type and horsepower category of the engines. CARB also imposes specific requirements for diesel-fueled APSs, dependent upon model year. For 2007 and later model year heavy-duty diesel trucks, a diesel-fueled APS must comply with California or federal nonroad emission standards and one of three additional requirements: (1) Route their exhaust into the truck's exhaust system so that the APS's PM emissions are controlled by the truck's PM trap; or (2) be equipped with a level 3 verified PM control strategy (*i.e.,* achieve an 85 percent PM reduction efficiency); or (3) obtain advance CARB approval to use other procedures to demonstrate an equivalent level of emission compliance. For 2006 and older model year trucks, diesel-fueled APS need only comply with the California or federal nonroad emission standards and test procedures applicable to the horsepower category of the engines.

With respect to CARB's alternative technology requirements, in the July 27, 2010 **Federal Register** notice, EPA sought comment on the following specific questions: (1) Does CARB's requirement that an APS using an internal combustion engine be certified to meet either California off-road or federal nonroad emission standards and test procedures meet the requirements for finding that it is within-the-scope of the authorization EPA issued for new nonroad engine standards, thus not requiring a full authorization?; [44] (2) If not, does CARB's requirement that an APS using an internal combustion engine be certified to meet either California off-road or federal nonroad emission standards and test procedures meet the requirements for a full authorization?; and (3) Does CARB's requirement that a diesel-fueled APS engine be certified to the California or federal 2007 and subsequent model year standards and meet one of three other listed requirements [45] meet the criteria for a full authorization?

1. Application of Full Authorization Analysis

With respect to the threshold question EPA asked as to which waiver analysis to apply to CARB's APS requirements, EPA received no comments. CARB asserts that because its APS requirements are linked to preexisting federal or California standards and certification requirements, the new APS requirements are within the scope of the prior authorizations for these engines. However, EPA does not believe that a within-the-scope analysis is appropriate in this circumstance. In the past, EPA has reviewed amendments to previously waived or authorized California standards for a determination of whether those amendments were within the scope of the previously waived or authorized standards. Here though, the APS requirements as imposed by California's Truck Idling Requirements are not amendments, but new regulations. Even though the APS

[44] 75 FR 8056 (February 23, 2010).

[45] The additional requirements are one of the following: (a) Exhaust routed into the truck's exhaust system and PM trap; (b) a level 3 verified PM control strategy; or (c) use of other procedures to demonstrate an equivalent level of emissions compliance.

requirements link to and rely upon previously authorized standards, they are newly applicable to all APS engines used in on-highway heavy-duty diesel vehicles, regardless of the model year of the engine. Because this is an additional requirement beyond that contemplated in previous nonroad and on-highway authorizations, EPA cannot apply its within-the-scope construct. Thus, we have reviewed all of California's APS requirements by application of our full authorization analysis.

2. California's Protectiveness Determination

Section 209(e)(2)(i) of the Act instructs that EPA cannot grant an authorization if the agency finds that CARB was arbitrary and capricious in its determination that its standards are, in the aggregate, at least as protective of public health and welfare as applicable federal standards. CARB's Board made a protectiveness determination in Resolution 05–55, finding that California's Truck Idling Requirements will not cause the California emission standards, in the aggregate, to be less protective of public health and welfare than applicable federal standards.[46] Furthermore, CARB asserts that ''there is no question'' its APS requirements are at least as protective of public health and welfare as applicable federal standards. To make this assertion, CARB highlights that EPA is authorized to regulate new nonroad engines, and only California may adopt emission standards and other emission-related requirements for in-use nonroad engines.[47] Accordingly, CARB points out that EPA has not adopted any emission standards or other requirements applicable to in-use APS engines.

EPA received one comment challenging California's protectiveness determination with respect to the APS requirements. OOIDA comments that ''in determining whether CARB's sleeper truck and alternative power source requirements should be approved, under any analysis, EPA should take care to fully consider and balance against the benefits to be gained by reducing emissions from idling sleeper trucks, the very real adverse impact such a requirement would have on the health and welfare of the operators of those trucks and negative effects on highway safety from truck operators not being properly rested.''[48] CARB counters that ''OOIDA's argument fails to present 'clear and compelling' evidence that California's protectiveness determinations are arbitrary and capricious; instead, it is only based on OOIDA's assumptions regarding the financial status and individual business decisions of numerous affected entities.''[49] EPA's review of California's protectiveness determination is limited under section 209(e)(2)(i). The Agency's review is highly deferential to California; the Clean Air Act does not leave room for EPA to second-guess the wisdom of California's policy. Contrary to OOIDA's request, it is not EPA's role in this context to consider and balance the emissions benefits against the potential negative impacts on operator health and welfare and highway safety. Instead, EPA is charged with determining whether California made its protectiveness determination arbitrarily or capriciously. Furthermore, for a number of reasons, OOIDA has not met its burden to show that California should be denied authorization because it has been arbitrary and capricious in making its protectiveness determination. First, OOIDA's comments are primarily directed at California's sleeper truck requirements, which as discussed above are not even subject to the section 209(a) waiver and section 209(e) authorization provisions. Second, the issues OOIDA raises with respect to California's protectiveness determination are not the type of issues that EPA traditionally considers as part of its evaluation of California's protectiveness determination. When evaluating California's protectiveness determination, EPA traditionally compares the stringency of the California and federal standards at issue in a given waiver or authorization request. That comparison is undertaken within the broader context of the previously waived California program, which relies upon protectiveness determinations that EPA previously found were not arbitrary and capricious. EPA refrains from conducting a more detailed examination of the secondary or tertiary effects California standards may have on health and the environment. Such an undertaking would seemingly go beyond the review that Congress intended.[50] Considering OOIDA's comments within the context of EPA's traditional protectiveness evaluation provides no additional opportunity to question California's protectiveness determination because OOIDA provides no indication that California's standards are less stringent than comparable federal standards. Third, even if we were to take into account OOIDA's concerns, OOIDA's secondary ''protectiveness'' concerns to do not present sufficient evidence to meet its burden of proof. OOIDA does not present any factual evidence or analysis of the specific health and welfare effects they expect to be caused by California's idling restrictions. Such evidence and analysis would be necessary to show that California's standards are less protective of health and welfare. Additionally, OOIDA does not dispute that California has presumed and allowed several avenues for drivers to use climate control and accessories during idling, particularly through the use of alternative power units. California also notes, in response to OOIDA, that it has provisions to allow extended idling during periods of extreme weather. Also, while OOIDA suggests that California's APS requirements are too expensive (which is more an issue of technological feasibility, discussed below, not protectiveness), there is no question that California allows the use of power to deal with climate control in sleeper car cabins. In sum, based on full consideration and evaluation of the totality of information CARB has supplied and the assertions OOIDA has presented, EPA cannot find that California's protectiveness determination was arbitrary and capricious.

Therefore, based on the record before us, EPA finds that opponents of the authorization have not shown that California was arbitrary and capricious in its determination that its standards are, in the aggregate, at least as protective of public health and welfare as applicable federal standards.

B. Need for California Standards To Meet Compelling and Extraordinary Conditions

Section 209(e)(2)(ii) of the Act instructs that EPA cannot grant an authorization if the agency finds that California ''does not need such California standards to meet compelling and extraordinary conditions * * *.'' This criterion restricts EPA's inquiry to whether California needs its own mobile source pollution program to meet compelling and extraordinary conditions, and not whether any given standards are necessary to meet such

[46] CARB Resolution 05–55, EPA–HQ–OAR–2010–0008, ''Be It Further Resolved that the Board hereby determines, pursuant to section 209(e)(2) of the federal Clean Air Act, that the emission standards and other requirements related to the control of emissions adopted as part of this Airborne Toxic Control Measure are, in the aggregate, at least as protective of public health and welfare as applicable federal standards * * * ''

[47] CARB Support Document at 34; *see EMA* v. *EPA,* 88 F.3d 1075 at 1089–1090.

[48] OOIDA Comments at 4.

[49] CARB Supplemental Comments at 10.

[50] *MEMA I,* 627 F.2d at 1121.

conditions.[51] As discussed above, for over forty years CARB has repeatedly demonstrated the need for its motor vehicle emissions program to address compelling and extraordinary conditions in California. In its Resolution 05–55, CARB affirmed its longstanding position that California continues to need its own motor vehicle and engine program to meet its serious air pollution problems. Likewise, EPA has consistently recognized that California continues to have the same ''geographical and climatic conditions that, when combined with the large numbers and high concentrations of automobiles, create serious pollution problems.'' Furthermore, no commenter has presented any argument or evidence to suggest that California no longer needs a separate motor vehicle emissions program to address compelling and extraordinary conditions in California. Therefore, EPA has determined that we cannot deny California a waiver for its new engine requirements under section 209(e)(2)(ii).

C. Consistency With Section 209 of the Clean Air Act

Section 209(e)(2)(iii) of the Act instructs that EPA cannot grant an authorization if California's standards and enforcement procedures are not consistent with section 209. As described above, EPA has historically evaluated this criterion for consistency with sections 209(a), 209(e)(1), and 209(b)(1)(C).

1. Consistency With Section 209(a)

To be consistent with section 209(a) of the Clean Air Act, California's APS requirements must not apply to new motor vehicles or engines. California's APS requirements apply to nonroad engines, not new on-highway motor vehicles or engines. CARB presents that although the APS are used on on-highway heavy-duty diesel vehicles and engines, they are auxiliary engines and are not used to propel motor vehicles or engines. CARB further states that because APS are regulated as nonroad engines, they fall within the regulatory definition of nonroad engine, and are, thus, consistent with section 209(a). No commenter presented otherwise; therefore, EPA cannot deny California's request on the basis that California's APS requirements are not consistent with section 209(a).

2. Consistency With Section 209(e)(1)

To be consistent with section 209(e)(1) of the Clean Air Act, California's APS requirements must not affect new farming or construction vehicles or engines that are below 175 horsepower, or new locomotives or their engines. CARB presents that APS engines are not used in locomotives and are not primarily used in farm and construction equipment vehicles. No commenter presented otherwise; therefore, EPA cannot deny California's request on the basis that California's APS requirements are not consistent with section 209(e)(1).

3. Consistency With Section 209(b)(1)(C)

The requirement that California's standards be consistent with section 209(b)(1)(C) of the Clean Air Act effectively requires consistency with section 202(a) of the Act. California standards are inconsistent with section 202(a) of the Act if there is inadequate lead-time to permit the development of technology necessary to meet those requirements, giving appropriate consideration to the cost of compliance within that time. California's accompanying enforcement procedures would also be inconsistent with section 202(a) if the federal and California test procedures were not consistent. The scope of EPA's review of whether California's action is consistent with section 202(a) is narrow. The determination is limited to whether those opposed to the authorization or waiver have met their burden of establishing that California's standards are technologically infeasible, or that California's test procedures impose requirements inconsistent with the federal test procedure.[52]

a. Technological Feasibility

Congress has stated that the consistency requirement of section 202(a) relates to technological feasibility.[53] Section 202(a)(2) states, in part, that any regulation promulgated under its authority ''shall take effect after such period as the Administrator finds necessary to permit the development and application of the requisite technology, giving appropriate consideration to the cost of compliance within such period.'' Section 202(a) thus requires the Administrator to first determine whether adequate technology already exists; or if it does not, whether there is adequate time to develop and apply the technology before the standards go into effect. The latter scenario also requires the Administrator to decide whether the cost of developing and applying the technology within that time is feasible. Previous EPA waivers are in accord with this position.[54] For example, a previous EPA waiver decision considered California's standards and enforcement procedures to be consistent with section 202(a) because adequate technology existed as well as adequate lead-time to implement that technology.[55] Subsequently, Congress has stated that, generally, EPA's construction of the waiver provision has been consistent with congressional intent.[56]

With respect to the general APS requirements, CARB presents that the technological feasibility is readily apparent. CARB believes this because the general APS requirement is that the APS complies with the California or federal nonroad emission standards and test procedures applicable for its fuel type and power category. Therefore, EPA has already determined the technological feasibility for these standards, either in its own federal rulemaking or by authorizing the underlying California standards in a previous authorization.[57] No commenter challenges the technological feasibility of California's general APS requirements. Thus, EPA cannot deny California's request on the basis of technological feasibility.

With respect to the specific APS requirements for diesel APSs, CARB presents that each option is technologically feasible in the specified lead-time. Broadly, CARB asserts that ''numerous technologies currently exist that can be used to comply with these requirements, including routing the exhaust from an APS into the exhaust system of the main engine, battery electric APSs, thermal energy storage systems, and on-shore electrical power infrastructures at truck stops.'' [58] CARB also presents information regarding the technological feasibility of each of its compliance options. For the first option (routing a diesel APS' exhaust upstream of the main engine's diesel particulate trap), CARB provided information establishing technological feasibility in its Initial Statement of Reasoning, which went unchallenged in its Final Statement of Reasoning.[59] CARB also

[51] *See* 74 FR 32744, 32761 (July 8, 2009); 49 FR 18887, 18889–18890 (May 3, 1984).

[52] *MEMA I,* 627 F.2d at 1126.

[53] H.R. Rep. No. 95–294, 95th Cong., 1st Sess. 301 (1977).

[54] *See, e.g.,* 49 FR 1887, 1895 (May 3, 1984); 43 FR 32182, 32183 (July 25, 1978); 41 FR 44209, 44213 (October 7, 1976).

[55] 41 FR 44209 (October 7, 1976).

[56] H.R. Rep. No. 95–294, 95th Cong., 1st Sess. 301 (1977).

[57] 60 FR 37440 (July 20, 1995), 65 FR 69763 (November 20, 2000), 68 FR 65702 (November 21, 2003), 71 FR 75536, and 75 FR 8056 (February 23, 2010).

[58] CARB Supplemental Comments at 4.

[59] CARB, ''Staff Report: Initial Statement of Reasons,'' EPA–HQ–OAR–2010–0317–0005; CARB,

Continued

represents that at least one manufacturer applied for certification of a fully integrated APS and truck exhaust system for the 2008 model year.[60] For the second option (inclusion of a CARB-verified, level 3 PM control), CARB presented in its initial May 9, 2008 support document that it had several verification applications, and that the technology was feasible.[61] Since that time, CARB has conditionally verified three level 3 PM control strategies that can be applied to APSs.[62] For the third option (an equivalent compliance strategy), CARB provides several currently available technologies that are acceptable alternatives to the first two compliance options, including battery powered APSs, thermal energy storage systems, truck stop electrification, and off-board power infrastructure.[63] For each of the options for compliance with the specific requirements for diesel APSs, CARB asserts that it gave appropriate consideration to cost of compliance within the lead-time provided.

In its comments, OOIDA expresses concerns related to the cost of APSs on truck drivers. OOIDA believes that faced with the added expense of an APS, truck drivers will decide not to invest in APSs and ''instead subject themselves to unhealthy and unsafe cab temperatures and conditions when hauling cargo in [California].'' [64] Section 202(a) consistency calls for a limited review of technological feasibility, including a cost analysis of the cost of new technology, if technology does not currently exist; section 202(a) does not allow EPA to conduct a more searching review of whether the costs are outweighed by the overall benefits of the California regulations. In this case, APS technologies are in existence and are being used in actual operation. In addition, CARB responds to OOIDA's cost concerns in its supplemental comments.[65] First, CARB points out that its Truck Idling Regulations allow truck drivers to override idling shutoff systems during extreme weather conditions. More specifically, CARB points towards its administrative record for support of its cost analysis. During the California rulemaking, CARB staff determined that ''the capital costs of [APS] technology could be recouped by truck owners or operators in as few as two and a half years, due to cost savings resulting from reduced fuel and truck maintenance costs.'' [66] CARB also relies on its APS cost estimates and response to comments regarding compliance costs.[67] CARB's rulemaking record with regard to cost effectively rebuts OOIDA's assertion that CARB ''*simply assumes* that all drivers have the ability to invest thousands of dollars in anti-idling equipment * * *.'' (emphasis added). In any case, while OOIDA's comments may be relevant to whether an operator would choose to add the APS, they are not relevant to whether APS technologies are infeasible. As discussed above, these technologies are being used in practice and are clearly feasible.

EPA did not receive any other comments suggesting that CARB's standards and test procedures are technologically infeasible. Consequently, based on the record, EPA cannot deny California's authorization based on technological infeasibility.

b. Consistency of Certification Procedures

California's standards and accompanying enforcement procedures would also be inconsistent with section 202(a) if the California test procedures were to impose certification requirements inconsistent with the federal certification requirements. Such inconsistency means that manufacturers would be unable to meet both the California and federal testing requirements using the same test vehicle or engine.[68]

CARB presents that none of the APS requirements pose any inconsistency as between California and federal test procedures. First, CARB asserts that its general APS requirements do not modify the test procedures specified for certifying a California or federal nonroad engine.[69] Second, CARB asserts that none of its three options to meet its APS requirements specific to diesel APS raise any issue with regard to test procedure consistency. For option 1, CARB again asserts that it does not alter test procedures specified for certifying a California or federal nonroad engine.[70] For options 2 and 3, CARB additionally points out no incompatibility issue can arise as between federal and California test procedures because EPA has no comparable federal standards or test procedures for CARB to conflict with.[71]

EPA received no comments suggesting that CARB's APS requirements pose a test procedure consistency problem. Therefore, based on the record, EPA cannot find that CARB's testing procedures are inconsistent with section 202(a). Consequently, EPA cannot deny CARB's request based on this criterion.

4. Other Issues

In its comments, ATA asserts that because California's APS requirements (those specific to diesel APSs on 2007 and subsequent model year heavy-duty diesel vehicles) apply to new diesel engines, they circumvent the consistency criteria of the Clean Air Act. ATA does not reference any of the sections of the Act which EPA has historically evaluated (*i.e.,* sections 209(a), 209(e)(1), and 209(b)(1)(C)); instead, ATA generally challenges California's ability to regulate APSs as inconsistent with federal standards. However, California's ability to regulate APSs as either new or in-use engines, and depart from federal standards—is clearly grounded in section 209 of the Clean Air Act. California may regulate new nonroad engines pursuant to section 209(e)(2)'s authorization provision; and section 209(e) impliedly allows California to regulate in-use nonroad engines. Additionally, as CARB points out, ATA's reliance on *Allway Taxi, Inc.* v. *City of New York,* is misplaced.[72] *Allway Taxi* concerned whether New York City could require emission controls for taxis in use. Those emission controls had not received a waiver of preemption, as New York City cannot receive one directly and at the time could not promulgate standards identical to California's. The court ultimately found that New York City could promulgate those emission controls, although noting that controls that took effect ''the moment after a new car is bought and registered * * * would be an obvious circumvention of the Clean Air Act.'' However, California has the authority to request a waiver of preemption (or authorization, for nonroad engines) for its standards under the Clean Air Act, and EPA has the authority to grant such request under section 209. *Allway Taxi* is not relevant

''Final Statement of Reasons,'' EPA–HQ–OAR–2010–0317–0010 (hereinafter ''FSOR'').

[60] CARB Support Document at 40.

[61] CARB Support Document at 42.

[62] CARB Supplemental Comments at 4.

[63] CARB Support Document at 44.

[64] OOIDA Comments at 3.

[65] CARB Supplemental Comments at 10–11.

[66] CARB Supplemental Comments at 11.

[67] *Id.; see* ISOR Section VII and FSOR at 49–54.

[68] *See, e.g.,* 43 FR 32182 (July 25, 1978).

[69] CARB Support Document at 38.

[70] CARB Support Document at 40.

[71] CARB Support Document at 45.

[72] CARB Supplemental Comments at 12. (''Allway Taxi primarily addressed the issue of whether states and localities that are preempted by the Clean Air Act from regulating new motor vehicles could nevertheless regulate emissions from in-use motor vehicles. That issue is clearly distinguishable from California's authority to adopt and to enforce standards for the nonroad engines in diesel-powered APSs. Unlike New York, California is expressly authorized by Congress to regulate both new and in-use nonroad engines (that are not conclusively preempted by section 209(e)(1) of the CAA) in diesel-powered APSs.'')

to this separate authority. It is this separate authority that is the subject of this proceeding. Furthermore, EPA's decision with respect to California's Truck Idling Requirements is circumscribed by the waiver criteria set forth in sections 209(b) and 209(e) of the Act. ATA's argument appears more directed at its policy goal of uniform idling regulations, but does not comport with the section 209 criteria, nor does it call into question any of EPA's section 209 analysis. Congress has provided a mechanism for California to have standards that are more stringent than those in other states, and ATA's argument seems to neglect this clear authority.

ATA also contends that EPA cannot grant a new authorization for California's APS requirements (again, those specific to diesel APSs on 2007 and subsequent model year heavy-duty diesel vehicles) because ''CARB has not complied with the lead time and stability requirements of section 202(a)(3)(C)'' of the Clean Air Act. This comment also does not comport with the section 209 criteria. California must take lead-time into account, and EPA must consider lead-time when evaluating California's regulations pursuant to section 209(e)'s consistency requirements. However, the lead-time inquiry EPA undertakes relates to technological feasibility. Specifically, consistency with section 202(a) requires the Administrator to first determine whether adequate technology already exists; or if it does not, whether there is adequate time to develop and apply the technology before the standards go into effect.[73] Congress has stated that, generally, this construction accords with congressional intent.[74] With respect to California's specific APS requirements for diesel APSs used on 2007 and later model year heavy-duty diesel vehicles, California demonstrated that all three compliance options are currently technologically feasible. No party—including ATA—presented otherwise. EPA then has no further inquiry into lead-time, because no additional requirement is imposed by the section 209 criteria.

5. Authorization Determination for California's APS Requirements

After a review of the information submitted by CARB and other parties to this proceeding, EPA finds that those opposing California's request have not met the burden of demonstrating that a waiver for California's APS requirements should be denied based on any of the three statutory criteria of section 209(e)(2). For this reason, EPA finds that California's APS requirements should be authorized.

D. Fuel-Fired Heater Requirements

California's Truck Idling Requirements also impose emission requirements on fuel-fired heaters. Fuel-fired heaters provide heat to truck cabs or sleeper berths and/or preheat engine blocks during cold weather. Fuel-fired heaters on 2007 and later model year trucks operating in California may now only operate fuel-fired heaters that comply with California's second generation of low emission vehicle (LEV II) regulations.

With respect to CARB's fuel-fired heater requirements, in the July 27, 2010 **Federal Register** notice, EPA sought comment on the following question: Are CARB's requirements pertaining to fuel-fired heaters, batteries, fuel cells, power inverter/chargers for on-shore power, and truck electrification preempted under section 209 of the Clean Air Act, and if so, do they meet the requirements for waiver under section 209(b) or authorization under section 209(e)?

CARB presents that its fuel-fired heater requirements are not preempted and, accordingly, do not require an authorization.[75] CARB asserts that because fuel-fired heaters are neither nonroad engines nor vehicles, they are not subject to section 209(e) preemption. EPA received no comments suggesting that CARB's fuel-fired heater requirements are subject to section 209(e) preemption. EPA confirms that fuel-fired heaters are not nonroad engines or vehicles, and are therefore not preempted under section 209(e) of the Clean Air Act.

E. California's Truck Idling Labeling Requirements

Engine manufacturers, original equipment manufacturers (OEMs), and internal combustion APSs manufacturers, as applicable, are required to produce and affix permanent labels to the hood of the truck. These labels are intended to assist CARB enforcement staff in clearly and easily identifying diesel trucks that comply with the California Truck Idling Requirements. As stated above, EPA is today issuing a waiver of preemption for the new engine requirements and an authorization for the APS requirements. California's engine and optional NO_X idling labeling requirements, which accompany the new engine requirements, are therefore included in the waiver of preemption for the new engine requirements. Similarly, California's auxiliary power system labeling requirements, which accompany the APS requirements, are therefore included in the authorization for the APS requirements.

F. Other Issues

OOIDA's comments present two other issues that generally challenge California's Truck Idling Requirements. First, OOIDA asserts that CARB should be prohibited from enforcing its Truck Idling Requirements until EPA approves them. Second, OOIDA asserts that federal laws other than the Clean Air Act may preempt California's Truck Idling Requirements. As EPA has stated on numerous occasions, sections 209(b) and 209(e) of the Clean Air Act limit our authority to deny California requests for waivers and authorizations to the three criteria listed therein. As a result, EPA has consistently refrained from denying California's requests for waivers and authorizations based on any other criteria.[76] In instances where the U.S. Court of Appeals has reviewed EPA decisions declining to deny waiver requests based on criteria not found in section 209(b), the Court has upheld and agreed with EPA's determination.[77] Neither of the issues OOIDA raises is among—or fits within the confines of—either explicitly or implicitly, the criteria listed under sections 209(b) and 209(e).[78] Therefore, in considering California's Truck Idling Requirements, EPA has not considered these issues.

III. Decision

The Administrator has delegated the authority to grant California section 209(b) waivers of preemption and section 209(e) authorizations to the Assistant Administrator for Air and Radiation. After evaluating CARB's Truck Idling Requirements, CARB's submissions, and the public comments from ATA and OOIDA, EPA is taking the following actions. First, EPA is granting a waiver of preemption to California for its new engine requirements. Second, EPA is granting

[73] EPA notes that even if the language in section 202(a)(1)(C) were relevant to its consistency analysis, that section by its own terms applies only to standards applicable to emissions from new heavy-duty on-highway motor vehicle engines, not the nonroad engines being regulated by California.

[74] H.R. Rep. No. 95–294, 95th Cong., 1st Sess. 301 (1977).

[75] CARB Support Document at 45.

[76] *See, e.g.,* 74 FR 32744, 32783 (July 8, 2009).

[77] *See Motor and Equipment Manufacturers Ass'n* v. *Nichols,* 142 F.3d 449, 462–63, 466–67 (DC Cir.1998), *Motor and Equipment Manufacturers Ass'n* v. *EPA,* 627 F.2d 1095, 1111, 1114–20 (DC Cir. 1979).

[78] OOIDA may raise these issues in a direct challenge to California's regulations in other forums, but these issues are not relevant to EPA's limited review under section 209.

an authorization to California for its auxiliary power system requirements.

My decision will affect not only persons in California, but also manufacturers outside the State who must comply with California's requirements in order to produce vehicles for sale in California. For this reason, I determine and find that this is a final action of national applicability for purposes of section 307(b)(1) of the Act. Pursuant to section 307(b)(1) of the Act, judicial review of this final action may be sought only in the United States Court of Appeals for the District of Columbia Circuit. Petitions for review must be filed by April 16, 2012. Judicial review of this final action may not be obtained in subsequent enforcement proceedings, pursuant to section 307(b)(2) of the Act.

IV. Statutory and Executive Order Reviews

As with past authorization and waiver decisions, this action is not a rule as defined by Executive Order 12866. Therefore, it is exempt from review by the Office of Management and Budget as required for rules and regulations by Executive Order 12866.

In addition, this action is not a rule as defined in the Regulatory Flexibility Act, 5 U.S.C. 601(2). Therefore, EPA has not prepared a supporting regulatory flexibility analysis addressing the impact of this action on small business entities.

Further, the Congressional Review Act, 5 U.S.C. 801, *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, does not apply because this action is not a rule for purposes of 5 U.S.C. 804(3).

Dated: February 8, 2012.

Gina McCarthy,

Assistant Administrator, Office of Air and Radiation.

[FR Doc. 2012–3690 Filed 2–15–12; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL RESERVE SYSTEM

Change in Bank Control Notices; Acquisitions of Shares of a Bank or Bank Holding Company

The notificants listed below have applied under the Change in Bank Control Act (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire shares of a bank or bank holding company. The factors that are considered in acting on the notices are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The notices are available for immediate inspection at the Federal Reserve Bank indicated. The notices also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing to the Reserve Bank indicated for that notice or to the offices of the Board of Governors. Comments must be received not later than March 1, 2012.

A. Federal Reserve Bank of Cleveland (Nadine Wallman, Vice President) 1455 East Sixth Street, Cleveland, Ohio 44101–2566:

1. Richard H. Thut, Orrville, to acquire up to 32.97% of the voting shares of FC Banc Corp, Bucyrus, Ohio, and thereby acquire Farmers Citizens Bank, Bucyrus, Ohio.

Board of Governors of the Federal Reserve System, February 13, 2012.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. 2012–3660 Filed 2–15–12; 8:45 am]

BILLING CODE 6210–01–P

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The applications listed below, as well as other related filings required by the Board, are available for immediate inspection at the Federal Reserve Bank indicated. The application also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)). If the proposal also involves the acquisition of a nonbanking company, the review also includes whether the acquisition of the nonbanking company complies with the standards in section 4 of the BHC Act (12 U.S.C. 1843). Unless otherwise noted, nonbanking activities will be conducted throughout the United States.

Unless otherwise noted, comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than March 12, 2012.

A. Federal Reserve Bank of Kansas City (Dennis Denney, Assistant Vice President) 1 Memorial Drive, Kansas City, Missouri 64198–0001:

1. *Summit Bancshares, Inc.,* to become a bank holding company by acquiring 100 percent of the voting shares of Summit Bank, both in Tulsa, Oklahoma.

Board of Governors of the Federal Reserve System, February 10, 2012.

Robert deV. Frierson,

Deputy Secretary of the Board.

[FR Doc. 2012–3583 Filed 2–15–12; 8:45 am]

BILLING CODE 6210–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Designation of a Class of Employees for Addition to the Special Exposure Cohort

AGENCY: National Institute for Occupational Safety and Health (NIOSH), Centers for Disease Control and Prevention, Department of Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: HHS gives notice of a decision to designate a class of employees from the Savannah River Site in Aiken, South Carolina, as an addition to the Special Exposure Cohort (SEC) under the Energy Employees Occupational Illness Compensation Program Act of 2000. On February 2, 2012, the Secretary of HHS designated the following class of employees as an addition to the SEC:

All employees of the Department of Energy, its predecessor agencies, and their contractors and subcontractors who worked at the Savannah River Site from January 1, 1953, through September 30, 1972, for a number of work days aggregating at least 250 work days, occurring either solely under this employment or in combination with work days within the parameters established for one or more other classes of employees included in the Special Exposure Cohort.

This designation will become effective on March 3, 2012, unless Congress provides otherwise prior to the effective date. After this effective date, HHS will publish a notice in the **Federal Register** reporting the addition of this class to the SEC or the result of any provision by Congress regarding the decision by HHS to add the class to the SEC.

FOR FURTHER INFORMATION CONTACT: Stuart L. Hinnefeld, Director, Division of Compensation Analysis and Support, NIOSH, 4676 Columbia Parkway, MS C–46, Cincinnati, OH 45226, Telephone 1–877–222–7570. Information requests can also be submitted by email to *DCAS@CDC.GOV.*

John Howard,

Director, National Institute for Occupational Safety and Health.

[FR Doc. 2012–3645 Filed 2–15–12; 8:45 am]

BILLING CODE 4163–19–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Designation of a Class of Employees for Addition to the Special Exposure Cohort

AGENCY: National Institute for Occupational Safety and Health (NIOSH), Centers for Disease Control and Prevention, Department of Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: HHS gives notice of a decision to designate a class of employees from the Linde Ceramics Plant in Tonawanda, New York, as an addition to the Special Exposure Cohort (SEC) under the Energy Employees Occupational Illness Compensation Program Act of 2000. On February 2, 2012, the Secretary of HHS designated the following class of employees as an addition to the SEC:

All Atomic Weapons Employees who worked in any area at the Linde Ceramics Plant in Tonawanda, New York, from November 1, 1947, through December 31, 1953, for a number of work days aggregating at least 250 work days, occurring either solely under this employment or in combination with work days within the parameters established for one or more other classes of employees included in the SEC.

This designation will become effective on March 3, 2012, unless Congress provides otherwise prior to the effective date. After this effective date, HHS will publish a notice in the **Federal Register** reporting the addition of this class to the SEC or the result of any provision by Congress regarding the decision by HHS to add the class to the SEC.

FOR FURTHER INFORMATION CONTACT: Stuart L. Hinnefeld, Director, Division of Compensation Analysis and Support, NIOSH, 4676 Columbia Parkway, MS C–46, Cincinnati, OH 45226, Telephone 1–877–222–7570. Information requests can also be submitted by email to *DCAS@CDC.GOV.*

John Howard,

Director, National Institute for Occupational Safety and Health.

[FR Doc. 2012–3646 Filed 2–15–12; 8:45 am]

BILLING CODE 4163–19–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Determination Concerning a Petition To Add a Class of Employees to the Special Exposure Cohort

AGENCY: National Institute for Occupational Safety and Health (NIOSH), Centers for Disease Control and Prevention, Department of Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: HHS gives notice of a determination concerning a petition to add a class of employees from the Hooker Electrochemical Company in Niagara Falls, New York, to the Special Exposure Cohort (SEC) under the Energy Employees Occupational Illness Compensation Program Act of 2000 (EEOICPA), 42 U.S.C. 7384q. On February 2, 2012, the Secretary of HHS determined that the following class of employees does not meet the statutory criteria for addition to the SEC as authorized under EEOICPA:

All employees who worked in any location at the Hooker Electrochemical Corporation during the operational period from January 1, 1943, through December 31, 1948, and during the residual period from January 1, 1949, to December 31, 1976.

FOR FURTHER INFORMATION CONTACT: Stuart L. Hinnefeld, Director, Division of Compensation Analysis and Support, National Institute for Occupational Safety and Health (NIOSH), 4676 Columbia Parkway, MS C–46, Cincinnati, OH 45226, Telephone 1–877–222–7570. Information requests can also be submitted by email to *DCAS@CDC.GOV.*

John Howard,

Director, National Institute for Occupational Safety and Health.

[FR Doc. 2012–3644 Filed 2–15–12; 8:45 am]

BILLING CODE 4163–19–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Solicitation of Nominations for Membership on the Secretary's Advisory Committee on Human Research Protections

AGENCY: Department of Health and Human Services, Office of the Secretary, Office of the Assistant Secretary for Health, Office for Human Research Protections.

ACTION: Notice.

Authority: 42 U.S.C. 217a, Section 222 of the Public Health Service Act, as amended. The Committee is governed by the provisions of Public Law 92–463, as amended (5 U.S.C. Appendix 2), which sets forth standards for the formation and use of advisory committees.

SUMMARY: The Office for Human Research Protections (OHRP), a program office in the Office of the Assistant Secretary for Health, Department of Health and Human Services (HHS), previously published a notice (76 FR 243, 19 Dec 2011, pp. 78660–78661) seeking nominations of qualified candidates to be considered for appointment as members of the Secretary's Advisory Committee on Human Research Protections (SACHRP). OHRP would like to announce a four week extension of the SACHRP nomination period. As a result of this extension, the nomination period will now end at the close of business on March 16, 2012.

DATES: Nominations for membership on the Committee must be received no later than March 16, 2012.

ADDRESSES: Nominations should be mailed or delivered to Dr. Jerry Menikoff, Director, Office for Human Research Protections, Department of Health and Human Services, 1101 Wootton Parkway, Suite 200, Rockville, MD 20852. Nominations will not be accepted by email or by facsimile.

FOR FURTHER INFORMATION CONTACT: Julia Gorey, Executive Director, SACHRP, Office for Human Research Protections, 1101 Wootton Parkway, Suite 200, Rockville, MD 20852, telephone: 240–453–8141. A copy of the Committee charter and list of the current members can be obtained by contacting Ms. Gorey, accessing the SACHRP Web site at *www.hhs.gov/ohrp/sachrp*, or requesting them via email at *sachrp@osophs.dhhs.gov.*

SUPPLEMENTARY INFORMATION: The Committee provides advice on matters pertaining to the continuance and improvement of functions within the authority of HHS directed toward protections for human subjects in research. Specifically, the Committee provides advice relating to the responsible conduct of research involving human subjects with particular emphasis on special populations such as neonates and children, prisoners, the decisionally impaired, pregnant women, embryos and fetuses; individuals and populations in international studies, investigator conflicts of interest and research involving individually identifiable samples, data or information.

In addition, the Committee is responsible for reviewing selected ongoing work and planned activities of

OHRP and other offices or agencies within HHS responsible for human subjects protection. These evaluations may include, but are not limited to, a review of assurance systems, the application of minimal research risk standards, the granting of waivers, education programs sponsored by OHRP, and the ongoing monitoring and oversight of institutional review boards and the institutions that sponsor research.

Nominations: OHRP is requesting nominations to fill four positions for voting members of SACHRP. Two positions will become vacant in July and two in October, 2012. Nominations of potential candidates for consideration are being sought from a wide array of fields, including, but not limited to: public health and medicine, behavioral and social sciences, health administration, and biomedical ethics. To qualify for consideration of appointment to the Committee, an individual must possess demonstrated experience and expertise in any of the several disciplines and fields pertinent to human subjects protection or clinical research.

The individuals selected for appointment to the Committee can be invited to serve a term of up to four years. Committee members receive a stipend and reimbursement for per diem and any travel expenses incurred for attending Committee meetings or conducting other business in the interest of the Committee. Interested applicants may self-nominate.

Nominations should be typewritten. The following information should be included in the package of material submitted for each individual being nominated for consideration: (1) A letter of nomination that clearly states the name and affiliation of the nominee, the basis for the nomination (i.e., specific attributes which qualify the nominee for service in this capacity), and a statement that the nominee is willing to serve as a member of the Committee; (2) the nominator's name, address, daytime telephone number, and the home or work address, telephone number, and email address of the individual being nominated; and (3) a current copy of the nominee's curriculum vitae. Federal employees should not be nominated for consideration of appointment to this Committee.

The Department makes every effort to ensure that the membership of HHS Federal advisory committees is fairly balanced in terms of points of view represented and the committee's function. Every effort is made to ensure that individuals from a broad representation of geographic areas, women and men, ethnic and minority groups, and the disabled are given consideration for membership on HHS Federal advisory committees. Appointment to this Committee shall be made without discrimination on the basis of age, race, ethnicity, gender, sexual orientation, disability, and cultural, religious, or socioeconomic status.

Individuals who are selected to be considered for appointment will be required to provide detailed information regarding their financial holdings, consultancies, and research grants or contracts. Disclosure of this information is necessary in order to determine if the selected candidate is involved in any activity that may pose a potential conflict with the official duties to be performed as a member of SACHRP.

Dated: February 10, 2012.

Jerry Menikoff,

Director, Office for Human Research Protections Executive Secretary, Secretary's Advisory Committee on Human Research Protections.

[FR Doc. 2012–3625 Filed 2–15–12; 8:45 am]

BILLING CODE 4150–36–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Meeting for Software Developers on the Technical Specifications for Common Formats for Patient Safety Data Collection and Event Reporting

AGENCY: Agency for Healthcare Research and Quality (AHRQ), HHS.

ACTION: Notice of public meeting.

SUMMARY: The Patient Safety and Quality Improvement Act of 2005, 42 U.S.C. 299b–21 to b–26, (Patient Safety Act) provides for the formation of Patient Safety Organizations (PSOs), which collect, aggregate, and analyze confidential information regarding the quality and safety of health care delivery. The Patient Safety Act (at 42 U.S.C. 299b–23) authorizes the collection of this information in a standardized manner, as explained in the related Patient Safety and Quality Improvement Final Rule, 42 CFR part 3 (Patient Safety Rule), published in the **Federal Register** on November 21, 2008: 73 FR 70731–70814. AHRQ coordinates the development of a set of common definitions and reporting formats (Common Formats) that allow health care providers to voluntarily collect and submit standardized information regarding patient safety events. In order to support the Common Formats, AHRQ has provided technical specifications to promote standardization by ensuring that data collected by PSOs and other entities are clinically and electronically comparable. More information on the Common Formats, including the technical specifications, can be obtained through AHRQ's PSO Web site: *http://www.PSO.AHRQ.GOV/index.html*.

The purpose of this notice is to announce a meeting to discuss the Common Formats technical specifications. This meeting is designed as an interactive forum where PSOs and software developers can provide input on these technical specifications. AHRQ especially requests input from those entities which have used AHRQ's technical specifications and implemented, or plan to implement, the formats electronically.

DATES: The meeting will be held from 10 a.m. to 3:30 p.m. on April 12, 2012.

ADDRESSES: The meeting will be held at the Hyatt Regency Bethesda, 7400 Wisconsin Avenue, Bethesda, MD 20814.

FOR FURTHER INFORMATION CONTACT:

Susan Grinder, Center for Quality Improvement and Patient Safety, AHRQ, 540 Gaither Road, Rockville, MD 20850; Telephone (toll free): (866) 403–3697; Telephone (local): (301) 427–1111; TTY (toll free): (866) 438–7231; TTY (local): (301) 427–1130; Email: *PSO@AHRQ.HHS.GOV*.

If sign language interpretation or other reasonable accommodation for a disability is needed, please contact the Food and Drug Administration (FDA) Office of Equal Employment Opportunity and Disability Management at (301) 827–4840, no later than March 28, 2012.

SUPPLEMENTARY INFORMATION:

Background

The Patient Safety Act and Patient Safety Rule establish a framework by which doctors, hospitals, skilled nursing facilities, and other health care providers may voluntarily report information regarding patient safety events and quality of care. Information that is assembled and developed by providers for reporting to PSOs and the information received and analyzed by PSOs—called "patient safety work product"—is privileged and confidential. Patient safety work product is used to identify events, patterns of care, and unsafe conditions that increase risks and hazards to patients. Definitions and other details about PSOs and patient safety work product are included in the Patient Safety Rule.

The Patient Safety Act and Patient Safety Rule require PSOs, to the extent practical and appropriate, to collect patient safety work product from providers in a standardized manner in order to permit valid comparisons of similar cases among similar providers. The collection of patient safety work product allows the aggregation of sufficient data to identify and address underlying causal factors of patient safety problems. Both the Patient Safety Act and Patient Safety Rule, including any relevant guidance, can be accessed electronically at: *http://www.PSO.AHRQ.GOV/REGULATIONS/REGULATIONS.htm*.

In collaboration with the interagency Federal Patient Safety Workgroup (PSWG), the National Quality Forum (NQF) and the public, AHRQ has developed Common Formats for two settings of care—acute care hospitals and skilled nursing facilities—in order to facilitate standardized data collection. The term ''Common Formats'' refers to the common definitions and reporting formats that allow health care providers to collect and submit standardized information regarding patient safety events. AHRQ's Common Formats include:

- Event descriptions (descriptions of patient safety events and unsafe conditions to be reported),
- Specifications for patient safety aggregate reports and individual event summaries,
- Delineation of data elements to be collected for different types of events to populate the reports,
- A user's guide and quick guide, and
- Technical specifications for electronic data collection and reporting.

AHRQ convenes the PSWG to assist AHRQ with developing and maintaining the Common Formats. The PSWG includes major health agencies within the Department of Health and Human Services (HHS)—the Centers for Disease Control and Prevention, Centers for Medicare & Medicaid Services, Food and Drug Administration, Health Resources and Services Administration, Indian Health Service, National Institutes of Health, National Library of Medicine, Office of the National Coordinator for Health Information Technology, Office of Public Health and Science, and Substance Abuse and Mental Health Services Administration—as well as the Department of Defense and Department of Veterans Affairs.

When developing Common Formats, AHRQ first reviews existing patient safety event reporting systems from a variety of health care organizations. In collaboration with the PSWG and Federal subject matter experts, AHRQ drafts and releases beta versions of the Common Formats for public review and comment.

Through a contract with AHRQ, NQF solicits feedback on the beta (and subsequent) versions of the Common Formats from private sector organizations and individuals. The NQF, a nonprofit organization that focuses on health care quality, then convenes an expert panel to review the comments received and provide feedback to AHRQ. Based upon the expert panel's feedback, AHRQ, in conjunction with the PSWG, further revises the Common Formats.

The technical specifications promote standardization of collected patient safety event information by specifying rules for data collection and submission, as well as by providing guidance for how and when to create data elements, their valid values, conditional and go-to logic, and reports. These specifications will ensure that data collected by PSOs and other entities have comparable clinical meaning.

The technical specifications also provide direction to software developers, so that the Common Formats can be implemented electronically, and to PSOs, so that the Common Formats can be submitted electronically to the PSO Privacy Protection Center (PSO PPC) for data de-identification and transmission to the Network of Patient Safety Databases (NPSD).

Most recently, AHRQ and the PSWG released the beta version of the Venous Thromboembolism (VTE) format for reporting of VTE-related patient safety events as announced in the **Federal Register** on November 1, 2011: 76 FR 67456–67457.

The Software Developer's meeting will focus on discussion of an anticipated Spring release—Hospital Common Formats 1.2—and the technical specifications, which provide direction to software developers that plan to implement the Common Formats electronically. The technical specifications are a critical component that allow for the aggregation of patient safety event data.

The technical specifications consist of the following:

- Data dictionary—defines data elements and their attributes (data element name, answer values, field length, guide for use, etc.) included in Common Formats;
- Clinical document architecture (CDA) implementation guide—provides instructions for developing a file to transmit the Common Formats Patient Safety data from the PSO to the PSO PPC using the Common Formats;
- Validation rules and errors document—specifies and defines the validation rules that will be applied to the Common Formats data elements submitted to the PSO PPC;
- Common Formats flow charts—diagrams the valid paths to complete generic and event specific formats (a complete event report);
- Local specifications—provides specifications for processing, linking and reporting on events and details specifications for reports; and
- Metadata registry—includes descriptive facts about information contained in the data dictionary to illustrate how such data corresponds with similar data elements used by other Federal agencies and standards development organizations [e.g., HL—7, International Standards Organization (ISO)].

Agenda, Registration and Other Information About the Meeting

On Thursday, April 12, 2012, the meeting will convene at 10 a.m. with an overview of the Common Formats, including the Hospital Common Formats Version 1.2 technical specifications, and next steps for upcoming Common Formats releases. AHRQ staff and contractors will review database functionality, which is available through the PSO PPC, for PSOs to generate aggregate reports with technical specifications. Finally, the meeting will review data submission both by PSOs and by vendors on behalf of a PSO. Throughout the meeting there will be interactive discussion to allow meeting participants not only to provide input, but also to respond to the input provided by others. A more specific proposed agenda will be posted before the meeting at *http://www.cvent.com/d/0cQkQx*.

AHRQ requests that interested persons register with the PSO PPC on the Internet at *http://www.cvent.com/d/0cQkQx/4W* to participate in the meeting. The contact at the PSO PPC is Rhonda Davis who can be reached by telephone at (866) 571–7712 and by email at supportpsoppc.ORG. Additional logistical information for the meeting is also available from the PSO PPC. The meeting space will accommodate approximately 150 participants. Interested persons are encouraged to register as soon as possible for the meeting. Non-registered individuals will be able to attend the meeting in person if space is available.

Prior to the meeting, AHRQ invites review of the technical specifications for Common Formats. The formats can be accessed through AHRQ's PSO Web site at *http://www.pso.AHRQ.GOV/formats/commonfmt.htm.* AHRQ is committed to continuing refinement of the Common Formats, and welcomes questions from prospective meeting participants and interested individuals on the technical specifications. These questions should be emailed to support@psoppc.ORG no later than March 21, 2012. AHRQ will use the input received at this meeting to further update and refine the Common Formats.

A summary of the meeting will be provided upon request. If you are unable to participate in the meeting and would like a copy of the summary, please send an email to supportpsoppc.ORG and it will be sent as soon as it is available after the meeting.

Dated: January 25, 2012.

Carolyn M. Clancy,

Director.

[FR Doc. 2012–2937 Filed 2–15–12; 8:45 am]

BILLING CODE 4160–90–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Advisory Board on Radiation and Worker Health (ABRWH or Advisory Board), National Institute for Occupational Safety and Health (NIOSH)

In accordance with section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), and pursuant to the requirements of 42 CFR 83.15(a), the Centers for Disease Control and Prevention (CDC), announces the following meeting of the aforementioned committee:

Board Public Meeting Times and Dates (All times are Pacific Time): 9:45 a.m.–5 p.m., February 28, 2012. 8:15 a.m.–6 p.m., February 29, 2012.

Public Comment Times and Dates (All times are Pacific Time): 5 p.m.–6:30 p.m.,* February 28, 2012.

* Please note that the public comment periods may end before the times indicated, following the last call for comments. Members of the public who wish to provide public comments should plan to attend public comment sessions at the start times listed.

Place: Waterfront Hotel, 10 Washington Street, Oakland, California 94607, Telephone: (510) 836–3800, Fax: (510) 832–5695, Audio Conference Call via FTS Conferencing, the USA toll-free number is 1–866–659–0537 with a pass code of 9933701.

Status: Open to the public, limited only by the space available. The meeting space accommodates approximately 150 people.

Background: The Advisory Board was established under the Energy Employees Occupational Illness Compensation Program Act of 2000 to advise the President on a variety of policy and technical functions required to implement and effectively manage the new compensation program. Key functions of the Advisory Board include providing advice on the development of probability of causation guidelines which have been promulgated by the Department of Health and Human Services (HHS) as a final rule, advice on methods of dose reconstruction which have also been promulgated by HHS as a final rule, advice on the scientific validity and quality of dose estimation and reconstruction efforts being performed for purposes of the compensation program, and advice on petitions to add classes of workers to the Special Exposure Cohort (SEC).

In December 2000, the President delegated responsibility for funding, staffing, and operating the Advisory Board to HHS, which subsequently delegated this authority to the CDC. NIOSH implements this responsibility for CDC. The charter was issued on August 3, 2001, renewed at appropriate intervals, and will expire on August 3, 2013.

Purpose: This Advisory Board is charged with (a) providing advice to the Secretary, HHS, on the development of guidelines under Executive Order 13179; (b) providing advice to the Secretary, HHS, on the scientific validity and quality of dose reconstruction efforts performed for this program; and (c) upon request by the Secretary, HHS, advise the Secretary on whether there is a class of employees at any Department of Energy facility who were exposed to radiation but for whom it is not feasible to estimate their radiation dose, and on whether there is reasonable likelihood that such radiation doses may have endangered the health of members of this class.

Matters To Be Discussed: The agenda for the Advisory Board meeting includes: NIOSH Program Update; Department of Labor (DOL) Program Update; Department of Energy (DOE) Program Update; NIOSH 10-Year Program Review Implementation; Status of Activities for Lawrence Berkeley National Laboratory and Stanford Linear Accelerator; SEC petitions for: Electro Metallurgical (Niagara Falls, NY), Hangar 481 (Kirtland Air Force Base); Weldon Spring Plant (Weldon Spring, MO), Sandia National Laboratories, Clinton Engineering Works (Oak Ridge, TN), Feed Materials Production Center (Fernald, Ohio), and Brookhaven National Laboratory; SEC Petition Status Updates; and Board Work Sessions.

The agenda is subject to change as priorities dictate.

In the event an individual cannot attend, written comments may be submitted in accordance with the redaction policy provided below. Any written comments received will be provided at the meeting and should be submitted to the contact person below well in advance of the meeting.

Policy on Redaction of Board Meeting Transcripts (Public Comment): (1) If a person making a comment gives his or her name, no attempt will be made to redact that name. (2) NIOSH will take reasonable steps to ensure that individuals making public comment are aware of the fact that their comments (including their name, if provided) will appear in a transcript of the meeting posted on a public Web site. Such reasonable steps include: (a) A statement read at the start of each public comment period stating that transcripts will be posted and names of speakers will not be redacted; (b) A printed copy of the statement mentioned in (a) above will be displayed on the table where individuals sign up to make public comments; (c) A statement such as outlined in (a) above will also appear with the agenda for a Board Meeting when it is posted on the NIOSH Web site; (d) A statement such as in (a) above will appear in the **Federal Register** Notice that announces Board and Subcommittee meetings. (3) If an individual in making a statement reveals personal information (e.g., medical information) about themselves that information will not usually be redacted. The NIOSH FOIA coordinator will, however, review such revelations in accordance with the Freedom of Information Act and the Federal Advisory Committee Act and if deemed appropriate, will redact such information. (4) All disclosures of information concerning third parties will be redacted. (5) If it comes to the attention of the DFO that an individual wishes to share information with the Board but objects to doing so in a public forum, the Designated Federal Officer will work with that individual, in accordance with the Federal Advisory Committee Act, to find a way that the Board can hear such comments.

Contact Person for More Information: Theodore Katz, M.P.A., Executive Secretary, NIOSH, CDC, 1600 Clifton Road NE., MS E–20, Atlanta, Georgia 30333, Telephone: (513) 533–6800, toll free: 1–800–CDC–INFO, email: *dcas@cdc.gov.*

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** Notices pertaining to announcements of meetings and other committee management activities, for both the Centers for Disease Control and Prevention and the Agency for Toxic Substances and Disease Registry.

Dated: February 7, 2012.

Elaine L. Baker,

Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 2012–3587 Filed 2–15–12; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[CMS–1594–N]

Medicare Program: Notice of Six Membership Appointments to the Advisory Panel on Hospital Outpatient Payment

AGENCY: Centers for Medicare & Medicaid Services (CMS), Department of Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: This notice announces six new membership appointments to the Advisory Panel on Hospital Outpatient Payment (HOP, the Panel). The six appointments to the 19 member Panel will each serve a 4-year period. Five of the new members will have terms that begin on February 1, 2012 and continuing through January 31, 2016. The sixth member's term will begin on August 1, 2012 and continuing through July 31, 2016. The purpose of the Panel is to advise the Secretary of the Department of Health and Human Services and the Administrator of the Centers for Medicare & Medicaid Services concerning the clinical integrity of the Ambulatory Payment Classification groups and their weights. The Panel also addresses and makes recommendations regarding supervision of outpatient services. The advice provided by the Panel will be considered as we prepare the annual updates for the hospital outpatient prospective payment system.

FOR FURTHER INFORMATION CONTACT: For additional information on the Panel meeting dates, agenda topics, copy of the charter, as well as updates to the Panel's activities, search our Internet Web site: *https://www.cms.gov/FACA/05_AdvisoryPanelonAmbulatoryPaymentClassificationGroups.asp#TopOfPage.* (**Note:** There is an UNDERSCORE after FACA/05_; there is no space.)

For other information regarding the Panel, contact Paula Smith, the Designated Federal Officer at CMS, Center for Medicare, Hospital and Ambulatory Policy Group, Division of Outpatient Care, 7500 Security Boulevard, Mail Stop C4–05–13, Baltimore, MD 21244–1850, phone (410) 786–4709. Information can also be obtained by contacting the CMS Advisory Committees' Information Line at 1–877–449–5659 (toll free) and (410) 786–9379 (local).

SUPPLEMENTARY INFORMATION:

I. Background

The Secretary of the Department of Health and Human Services (the Secretary) is required by section 1833(t)(9)(A) of the Social Security Act (the Act) (42 U.S.C. 1395l(t)(9)(A)) and section 222 of the Public Health Service Act (PHS Act) (42 U.S.C. 217a) to consult with an expert outside advisory panel on the clinical integrity of the Ambulatory Payment Classification groups and weights. The Advisory Panel on Hospital Outpatient Payment (HOP, the Panel) is governed by the provisions of the Federal Advisory Committee Act (FACA) (Pub. L. 92–463, as amended (5 U.S.C. Appendix 2), which sets forth standards for the formation and use of advisory panels. The Panel Charter provides that the Panel shall meet up to 3 times annually. We consider the technical advice provided by the Panel as we prepare the proposed and final rules to update the outpatient prospective payment system for the next calendar year.

The Panel shall consist of a chair and up to 19 members who are full-time employees of hospitals, hospital systems, or other Medicare providers. The Secretary or a designee selects the Panel membership based upon either self-nominations or nominations submitted by Medicare providers and other interested organizations. New appointments are made in a manner that ensures a balanced membership under the FACA guidelines.

The Panel presently consists of the following members and a Chair: (The asterisk [*] indicates a Panel member whose term expires on July 31, 2012).

- Edith Hambrick, M.D., J.D., Chair, CMS Medical Officer.
- Ruth L. Bush, M.D., M.P.H.
- Kari S. Cornicelli, C.P.A., FHFMA.
- Dawn L. Francis, M.D., M.H.S.
- Kathleen Graham, R.N., M.S.H.A.*
- David A. Halsey, M.D.
- Brian D. Kavanagh, M.D., MPH.
- Judith T. Kelly, R.H.I.T., R.H.I.A., C.C.S.
- Scott Manaker, M.D., Ph.D.
- John Marshall, CRA, RCC, CIRCC, RT(R), FAHRA.
- Jacqueline Phillips.
- Randall A. Oyer, M.D.
- Daniel J. Pothen, M.S., RHIA, CHPS.
- Gregory Przybylski, M.D.
- Marianna V. Spanaki-Varela, MD, Ph.D., M.B.A.

II. Provisions of the Notice

We published a notice in the **Federal Register** on November 25, 2011, entitled ''Medicare Program; Renaming and Other Changes to the Advisory Panel on Hospital Outpatient Payment Charter (Formerly the Advisory Panel on Ambulatory Payment Classification Groups) and Request for Nominations'' (76 FR 72708). The notice requested nominations to be added to the Panel by replacing one Panel member whose term expires on July 31, 2012; replacing one Panel member who resigned; and by adding four new Panel members (two of these designated as Critical Access Hospital representatives (see the November 30, 2011 final rule, (76 FR 74363)) to address appropriate supervision level for hospital outpatient services. As a result of that November 25, 2012 notice and the November 30, 2011 final rule, we are announcing six new members to the Panel. Their appointments are for 4-year terms commencing on February 1, 2012 and August 1, 2012.

New Appointments to the Panel—The new members of the Panel with terms beginning on February 1, 2012 and continuing through January 31, 2016 are as follows:

- *Lanny Copeland, M.D.,*
- *Jim Nelson,*
- *Leah Osbahr,*
- *Traci Rabine; and*
- *Gale Walker*

The new member of the Panel with a term beginning on August 1, 2012, and continuing through July 31, 2016 is:

- *Karen Borman, M.D.*

III. Collection of Information Requirements

This document does not impose information collection and recordkeeping requirements. Consequently, it need not be reviewed by the Office of Management and Budget under the authority of the Paperwork Reduction Act of 1995 (44 U.S.C. 35).

(Catalog of Federal Domestic Assistance Program; No. 93.773 Medicare—Hospital Insurance Program; and No. 93.774, Medicare—Supplementary Medical Insurance Program)

Section 1833(t)(9)(A) of the Act (42 U.S.C. 1395l(t)(9)(A)). The Panel is governed by the provisions of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2).

Dated: February 8, 2012.

Marilyn Tavenner,

Acting Administrator, Centers for Medicare & Medicaid Services.

[FR Doc. 2012–3643 Filed 2–15–12; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2012–N–0123]

Design and Methodology for Postmarket Surveillance Studies Under Section 522 of the Federal Food, Drug, and Cosmetic Act; Public Workshop

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice of public workshop.

SUMMARY: The Food and Drug Administration (FDA) is announcing a public workshop entitled ''Design and Methodology for Postmarket Surveillance Studies under Section 522 of the Federal Food, Drug and Cosmetic Act''. The purpose of the public workshop is to provide a forum for discussion among FDA, industry, governmental agencies, academia, clinicians and various stakeholders with experience in epidemiology, statistics, and biomedical research to advance the design and methodologies for medical device surveillance studies in the ''postmarket'' setting, i.e., after FDA premarket approval or clearance of the device and marketing of the device has begun.

DATES: The meeting will be held on March 7, 2012, from 8 a.m. to 5:30 p.m.

ADDRESSES: The meeting will be held at the FDA White Oak Campus, 10903 New Hampshire Ave., Bldg. 31, Rm 1503 (the Great Room), Silver Spring, MD 20993. For parking and security information, please visit the following Web site: *http://www.fda.gov/AboutFDA/WorkingatFDA/BuildingsandFacilities/WhiteOakCampusInformation/ucm241740.htm.* The public workshop will also be available to be viewed online via webcast.

FOR FURTHER INFORMATION CONTACT: Samantha Jacobs, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Rm. 4201C, Silver Spring, MD 20993, 301–796–6897, email: *samantha.jacobs@fda.hhs.gov*; or Mary Beth Ritchey, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Rm. 4118, Silver Spring, MD 20993, 301–796–6638, email: *maryelizabeth.ritchey@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION:

Registration: To register for the public workshop, please visit the following Web site: *http://www.fda.gov/MedicalDevices/NewsEvents/WorkshopsConferences/ucm289465.htm* (or go to *http://www.fda.gov* and select the FDA Medical Devices News & Events—Workshops & Conferences calendar and select this public workshop from the posted events list). Please provide complete contact information for each attendee, including name, title, affiliation, address, email, and telephone number. For persons interested in attending this workshop and without Internet access, please call one of the people listed in the **FOR FURTHER INFORMATION CONTACT** section in this document in order to register. Registrants will receive confirmation once they have been accepted. You will be notified if you are on a waitlist. There is no fee to attend the public workshop, but attendees must register in advance. Registration will be on a first-come, first-served basis. Persons interesting in attending this workshop must register online by February 29, 2012. Registration is mandatory as space is limited and onsite registration will not be available. FDA may limit the number of participants from each organization.

If you need special accommodations due to a disability, please contact Susan Monahan at *susan.monahan@fda.hhs.gov* no later than March 1, 2012.

Security: Non-U.S. citizens are subject to additional security screening, and they should register as soon as possible. Entrance for the public meeting participants (non-FDA employees) is through Building 1 where routine security check procedures will be performed. For parking and security information, please visit the Web site address in the **ADDRESSES** section of this document.

Streaming Webcast of the Public Workshop: This workshop will also be webcast. Persons interested in viewing the webcast must register online by 5 p.m. on February 29, 2012. Early registration is recommended because webcast connections are limited. Organizations are requested to register all participants, but view using one connection per location. Webcast participants will be sent technical system requirements after registration, and will be sent connection access information after March 1, 2012. If you have never attended a Connect Pro meeting before, test your connection at: *https://collaboration.fda.gov/common/help/en/support/meeting_test.htm.* To get a quick overview of the Connect Pro program, visit: *http://www.adobe.com/go/connectpro_overview.* (FDA has verified the Web site addresses in this document, but FDA is not responsible for any subsequent changes to the Web sites after this document publishes in the **Federal Register**.)

Background: Under section 522(a) of the Federal Food, Drug and Cosmetic Act (FD&C Act), enacted by the Food and Drug Administration Modernization Act of 1997 (FDAMA) (Pub. L. 105–115, § 212, 111 Stat. 2346), codified at 21 U.S.C. 360*l*(a), FDA may order a manufacturer to conduct postmarket surveillance for any Class II or Class III device (i) Intended to be implanted in the human body for more than 1 year or to be used to sustain or support life outside a device user facility, or (ii) whose failure would be reasonably likely to have serious adverse health consequences. The Food and Drug Administration Amendments of 2007 (FDAAA) (Pub. L. 110–85, § 307, 121 Stat. 865) expanded the scope of section 522 to include devices intended for pediatric use.

Agenda for the Public Workshop

1. Why are we holding this public workshop?

The purpose of the proposed workshop is to facilitate discussion among the FDA, industry, governmental agencies, academia, clinicians, and key stakeholders with experience in epidemiology, statistics, and biomedical research in the scientific community to advance the design and methodologies for medical device surveillance studies in the postmarket setting.

2. Who is the target audience for this public workshop? Who should attend this public workshop?

This workshop is open to all interested parties. The target audience is professionals in the scientific community interested in advancing the infrastructure and methodology for postmarket surveillance studies.

3. What are the topics we intend to address at the public workshop?

We intend to discuss a large number of issues at the workshop, including, but not limited to the following:

• Regulations for postmarket surveillance studies,

• Challenges and opportunities for collaborative efforts,

• Innovative methodologies and scientific infrastructure to promote innovation,

• Role of networks, registries and observational studies,

4. Where can I find out more about this public workshop?

Background information on the public workshop, registration information, the agenda, information about lodging, and other relevant information will be posted, as it becomes available, on the Internet at *http://www.fda.gov/cdrh/meetings.html.*

Comments: Regardless of attendance at the public workshop, interested persons may submit electronic comments, or written comments by April 6, 2012. Submit electronic comments to *http://www.regulations.gov.* Submit written comment to the Division of Dockets Management (HFA–305), Food and Drug Administration 5630 Fishers Lane, rm, 1061, Rockville, MD 20852. Comments are to be identified with the docket number found in brackets in the heading of this document. In addition, when responding to specific topics listed in paragraph 3 of the ''Agenda for the Public Workshop'' section of this document, please identify the topic you are addressing. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday.

Transcripts: Please be advised that as soon as a transcript is available, it will be accessible at *http://www.regulations.gov.* It may be viewed at the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, rm. 1061, Rockville, MD 20852. A transcript will also be available in either hardcopy or on CD–ROM, after submission of a Freedom of Information request. Any written request for a transcript is to be sent to the Division of Freedom of Information. Written requests are to be sent to Division of Freedom of Information (ELEM–1029), Food and Drug Administration, 12420 Parklawn Dr., Element Bldg., Rockville, MD 20857. A link to the transcripts will also be available on the Internet at *http://www.fda.gov/MedicalDevices/NewsEvents/WorkshopsConferences/default.htm* (select this public workshop from the posted events list), approximately 45 days after the public workshop.

Dated February 10, 2012.

Nancy K. Stade,

Deputy Director for Policy, Center for Devices and Radiological Health.

[FR Doc. 2012–3606 Filed 2–15–12; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Health Resources and Services Administration

Agency Information Collection Activities: Proposed Collection: Comment Request

In compliance with the requirement for opportunity for public comment on proposed data collection projects (section 3506(c)(2)(A) of Title 44, United States Code, as amended by the Paperwork Reduction Act of 1995, Pub. L. 104–13), the Health Resources and Services Administration (HRSA) publishes periodic summaries of proposed projects being developed for submission to the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995. To request more information on the proposed project or to obtain a copy of the data collection plans and draft instruments, email *paperwork@hrsa.gov* or call the HRSA Reports Clearance Officer at (301) 443–1984.

Comments are invited on: (a) The proposed collection of information for the proper performance of the functions of the Agency; (b) the accuracy of the Agency's estimate of the burden of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Proposed Project: Maternal, Infant, and Early Childhood Home Visiting Program Information System (OMB No. 0915–xxxx)—[New]

On March 23, 2010, the President signed into law the Patient Protection and Affordable Care Act of 2010 (Pub. L. 111–148), historic and transformative legislation designed to make quality, affordable health care available to all Americans, reduce costs, improve health care quality, enhance disease prevention, and strengthen the health care workforce. Through a provision authorizing the creation of the Maternal, Infant, and Early Childhood Home Visiting (MIECHV) Program, the Act responds to the diverse needs of children and families in communities at risk and provides an unprecedented opportunity for collaboration and partnership at the Federal, State and community levels to improve health and development outcomes for at-risk children through evidence-based home visiting programs. The MIECHV Program is designed: (1) To strengthen and improve the programs and activities carried out under Title V; (2) to improve coordination of services for at-risk communities; and (3) to identify and provide comprehensive services to improve outcomes for families who reside in at-risk communities.

The Social Security Act, Title V, Section 511 (42 U.S.C. 711), as amended by the Patient Protection and Affordable Care Act of 2010, requires that MIECHV grantees collect data to measure improvements for eligible families in six specified areas (referred to as ''benchmark areas'') that encompass the major goals for the program. The Supplemental Information Request for the Submission of the Updated State Plan for a State Home Visiting Program (SIR), published on February 8, 2011, further listed a variety of constructs under each benchmark area for which grantees were to select and submit relevant performance measures. Per Section 511(d)(1)(B)(i) of the legislation, no later than 30 days after the end of the third year of the program, grantees are required to demonstrate improvement in at least four of the six benchmark areas. The SIR and subsequent MIECHV guidance documents for both competitive and formula grants also require that grantees report annually on the constructs under each benchmark area, as well as on demographic, service utilization, budgetary and other administrative data related to program implementation.

The proposed data collection and reporting forms were developed by an internal MIECHV workgroup in consultation with Home Visiting Model Developers and selected grantees. The data collected from the proposed forms will be used to track the grantees' progress in demonstrating improvement under each benchmark area and to provide an overall picture of the population being served. The proposed data collection forms are as follows:

Form 1—Demographic and Service Utilization Data for Enrollees and Children: This form will request data to determine the unduplicated number of participants and of participant groups by primary insurance coverage. This form will also request data on the demographic characteristics of program participants. For example, data will be collected on the race/ethnicity of program participants and household demographics including income data.

Form 2—State Performance Measures Template: Grantees have already selected relevant performance measures for the legislatively identified benchmark areas. This form provides a template for grantees to report aggregate data on their State-selected performance measures.

While there will be variation in the data collection and reporting burden to the grantees based on the number of families served and state data system capacity, the estimated average annual burden is as follows:

Reporting document	Number of respondents	Responses per respondent	Total responses	Burden hours per response	Total burden hours
Form 1: Demographic and Service Utilization Data for Enrollees and Children	56	1	56	731	40,936
Form 2: State Performance Measures Template	56	1	56	313	17,528
Total	56	....	56	....	58,464

Email comments to *paperwork@hrsa.gov* or by mail to the HRSA Reports Clearance Officer, Room 10–29, Parklawn Building, 5600 Fishers Lane, Rockville, MD 20857. Written comments should be received within 60 days of this notice.

Dated: February 10, 2012.

Reva Harris,

Acting Director, Division of Policy and Information Coordination.

[FR Doc. 2012–3710 Filed 2–15–12; 8:45 am]

BILLING CODE 4165–15–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Citizenship and Immigration Services

Agency Information Collection Activities: Extension of an Existing Information Collection Request; Comment Request

ACTION: *60-Day Notice of Information Collection Under Review:* Form N–25, Request for Verification of Naturalization.

The Department of Homeland Security, U.S. Citizenship and Immigration Services (USCIS) will be submitting the following information collection request for review and clearance in accordance with the Paperwork Reduction Act of 1995. The information collection notice, OMB Control Number 1615–0049, is published in the **Federal Register** to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted for sixty days until April 16, 2012.

During this 60-day period USCIS will be evaluating whether to revise the Form N–25. Should USCIS decide to revise this form it will advise the public when it publishes the 30-day notice in the **Federal Register** in accordance with the Paperwork Reduction Act. The public will then have 30-days to comment on any revisions to this form.

Written comments and suggestions regarding items contained in this notice and especially with regard to the estimated public burden and associated response time should be directed to the Department of Homeland Security (DHS), USCIS, Chief, Regulatory Products Division, Clearance Office, 20 Massachusetts Avenue NW., Washington, DC 20529. Comments may also be submitted to DHS via facsimile to 202–272–0997, or via email at *uscisfrcomment@dhs.gov.* When submitting comments by email, please add the OMB Control Number 1615–0049 in the subject box.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information should address one or more of the following four points:

(1) Evaluate whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agency's estimate of the burden of the collection of information, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques, or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Overview of This Information Collection

(1) *Type of Information Collection:* Extension of an existing information collection.

(2) *Title of the Form/Collection:* Request for Verification of Naturalization.

(3) *Agency form number, if any, and the applicable component of the Department of Homeland Security sponsoring the collection:* Form N–25. U.S. Citizenship and Immigration Services.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract: Primary:* Not for Profit Institutions. This form will allow U.S. Citizenship and Immigration Services (USCIS) to obtain verification from the courts that a person claiming to be a naturalized citizen has, in fact, been naturalized.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* 1,000 responses at 15 minutes (.25) per response.

(6) *An estimate of the total public burden (in hours) associated with the collection:* 250 annual burden hours.

If you have additional comments, suggestions, or need a copy of the information collection instrument, please visit: *http://www.regulations.gov/search/index.jsp.*

We may also be contacted at: USCIS, Regulatory Management Division, 20 Massachusetts Avenue NW., Washington, DC 20529, telephone number 202–272–8377.

Dated: February 10, 2012.

William Bacon,

Deputy Chief, Office of the Executive Secretariat, U.S. Citizenship and Immigration Services, Department of Homeland Security.

[FR Doc. 2012–3665 Filed 2–15–12; 8:45 am]

BILLING CODE 9111–97–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Citizenship and Immigration Services

Agency Information Collection Activities: Form I–361, Extension of a Currently Approved Information Collection; Comment Request

ACTION: 60-Day Notice of Information Collection Under Review: Form I–361, Affidavit of Financial Support and Intent To Petition for Legal Custody for Public Law 97–359 Amerasian.

The Department of Homeland Security, U.S. Citizenship and Immigration Services (USCIS), will be submitting the following information collection request for review and clearance in accordance with the Paperwork Reduction Act of 1995. The information collection notice is published in the **Federal Register** to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted for sixty days until April 16, 2012.

During this 60-day period, USCIS will be evaluating whether to revise the Form I–361. Should USCIS decide to revise Form I–361 we will advise the public when we publish the 30-day notice in the **Federal Register** in accordance with the Paperwork Reduction Act. The public will then have 30 days to comment on any revisions to the Form I–361.

Written comments and suggestions regarding items contained in this notice and especially with regard to the estimated public burden and associated response time should be directed to the Department of Homeland Security (DHS), USCIS, Chief, Regulatory Products Division, Office of the Executive Secretariat, Clearance Office, 20 Massachusetts Avenue NW., Washington, DC 20529–2020. Comments may also be submitted to DHS via facsimile to 202–272–0997, or via email at *uscisfrcomment@dhs.gov.* When submitting comments by email please add the OMB Control Number 1615–0021 in the subject box.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information should address one or more of the following four points:

(1) Evaluate whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agencies estimate of the burden of the collection of information, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Overview of This Information Collection

(1) *Type of Information Collection:* Extension of a currently approved information collection.

(2) *Title of the Form/Collection:* Affidavit of Financial Support and Intent to Petition for Legal Custody for Public Law 97–359 Amerasian.

(3) *Agency form number, if any, and the applicable component of the Department of Homeland Security sponsoring the collection:* Form I–361. U.S. Citizenship and Immigration Services.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract: Primary:* Individuals and households. The information on this form is used in support of Form I–360 (Petition for Amerasian, Widow(er), or Special Immigrant) to ensure financial support for Public Law 97–359 Amerasian. The affidavit is used only to sponsor individuals eligible for immigration under Public Law 97–359.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* 50 responses at 30 minutes (.50) per response.

(6) *An estimate of the total public burden (in hours) associated with the collection:* 25 annual burden hours.

If you have additional comments, suggestions, or need a copy of the information collection instrument, please visit the USCIS Web site at: *http://www.regulations.gov/.*

We may also be contacted at: USCIS, Regulatory Products Division, Office of the Executive Secretariat, 20 Massachusetts Avenue NW., Washington, DC 20529–2020, Telephone number 202–272–8377.

Dated: February 10, 2012.

William Bacon,

Deputy, Office of the Executive Secretariat, U.S. Citizenship and Immigration Services, Department of Homeland Security.

[FR Doc. 2012–3668 Filed 2–15–12; 8:45 am]

BILLING CODE 9111–97–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Citizenship and Immigration Services

Agency Information Collection Activities: Forms G–1041 and G–1041A, Extension of a Currently Approved Information Collection; Comment Request

ACTION: 60-Day Notice of Information Collection Under Review: Forms G–1041 and G–1041A, Genealogy Index Search Request and Genealogy Records Request.

The Department of Homeland Security, U.S. Citizenship and Immigration Services (USCIS) will be submitting the following information collection request for review and clearance in accordance with the Paperwork Reduction Act of 1995. The information collection notice is published in the **Federal Register** to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted for sixty days until April 16, 2012.

During this 60 day period, USCIS will be evaluating whether to revise forms G–1041 and G–1041A. Should USCIS decide to revise forms G–1041 and G–1041A, we will advise the public when we publish the 30-day notice in the **Federal Register** in accordance with the Paperwork Reduction Act. The public will then have 30 days to comment on any revisions to forms G–1041 and G–1041A.

Written comments and suggestions regarding items contained in this notice and especially with regard to the estimated public burden and associated response time should be directed to the Department of Homeland Security (DHS), USCIS, Chief, Regulatory Products Division, 20 Massachusetts Avenue NW., Washington, DC 20529–2020. Comments may also be submitted to DHS via facsimile to 202–272–8352, or via email at *uscisfrcomment@dhs.gov.* When submitting comments by email, please add the OMB Control Number 1615–0096 in the subject box.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information should address one or more of the following four points:

(1) Evaluate whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agency's estimate of the burden of the

collection of information, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques, or other forms of information technology, e.g., permitting electronic submission of responses.

Overview of This Information Collection

(1) *Type of Information Collection:* Extension of an existing information collection.

(2) *Title of the Forms/Collections:* Genealogy Index Search Request and Genealogy Records Request.

(3) *Agency form number, if any, and the applicable component of the Department of Homeland Security sponsoring the collection:* Forms G–1041 and G–1041A. U.S. Citizenship and Immigration Services.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract: Primary:* Individuals and households. USCIS will use these forms will to facilitate an accurate and timely response to genealogy index search and records requests.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* Form G–1041—2,570 responses (electronically submitted) at .50 hours (30 minutes) per response and 1,080 responses (submitted by mail) at .58 hours (35 minutes).

Form G–1041A—1,683 responses (electronically submitted) at 1 hour (60 minutes) per response and 823 responses (submitted by mail) at 1.08 hours (68 minutes).

(6) *An estimate of the total public burden (in hours) associated with the collection:* 4,483.4 annual burden hours.

If you have additional comments, suggestions, or need a copy of the information collection instrument, please visit: *http://www.regulations.gov/search/index.jsp*.

We may also be contacted at: USCIS, Regulatory Products Division, 20 Massachusetts Avenue NW., Washington, DC 20529–2020, telephone number 202–272–8377.

Dated: February 10, 2012.

William Bacon,

Deputy Chief, Office of the Executive Secretariat, U.S. Citizenship and Immigration Services, Department of Homeland Security.

[FR Doc. 2012–3666 Filed 2–15–12; 8:45 am]

BILLING CODE 9111–97–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–R6–R–2011–N212; FF06R06000–FXRS1265066CCP0S2–123]

Establishment of Dakota Grassland Conservation Area, North Dakota and South Dakota

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice.

SUMMARY: This notice advises the public that the U.S. Fish and Wildlife Service (Service) has established the Dakota Grassland Conservation Area, the 554th unit of the National Wildlife Refuge System. The Service established the Dakota Grassland Conservation Area on September 21, 2011, with the purchase of a 318.18-acre grassland easement in Walworth County, South Dakota.

ADDRESSES: A map depicting the approved Refuge boundary and other information regarding the Refuge is available on the Internet at *http://www.fws.gov/mountain-prairie/planning/*.

FOR FURTHER INFORMATION CONTACT: Nick Kaczor, Planning Team Leader, Division of Refuge Planning, USFWS, P.O. Box 25486, DFC, Denver, CO 80225. *http://www.fws.gov/mountain-prairie/planning/*.

SUPPLEMENTARY INFORMATION: The Service established the Dakota Grassland Conservation Area in the eastern parts of North Dakota and South Dakota, which cover all counties north and east of the Missouri River except those in the existing Dakota Tallgrass Prairie Wildlife Management Area. The Service will continue to conserve wetland and grassland resources in the conservation area, primarily through the purchase of perpetual easements from willing sellers. These wetland and grassland easements will connect and expand existing lands under conservation protection.

The area's strong and vibrant rural lifestyle, of which agriculture is the dominant land use, is one of the key components to ensuring habitat integrity and wildlife resource protection. Based on anticipated levels of landowner participation, objectives for the conservation area are to protect 240,000 acres of wetland and 1.7 million acres of critical grassland habitat. The conservation area is a landscape-scale effort to conserve populations of priority species in a highly diverse and endangered ecosystem over an area of approximately 29.6 million acres. Therefore, it is important to incorporate the elements of strategic habitat conservation (SHC) to ensure effective conservation. SHC entails strategic biological planning and conservation design, integrated conservation delivery, monitoring, and research at ecoregional scales.

This conservation area allows the Service to purchase critical wetland and grassland easements, using the acquisition authority of the Fish and Wildlife Act of 1956 (16 U.S.C. 742a–j). In response to comments received during the public review of the draft environmental assessment (EA) and land protection plan (LPP), the Service included the authority of the Migratory Bird Conservation Act of 1929 (16 U.S.C. 715–715d, 715e, 715f–r). The Federal money used to acquire conservation easements is from the Land and Water Conservation Fund Act of 1965, as amended (16 U.S.C. 460l–4 through 11; funds received under this act are derived primarily from oil and gas leases on the Outer Continental Shelf, motorboat fuel taxes, and the sale of surplus Federal property), and the sale of Federal Duck Stamps [Migratory Bird Hunting and Conservation Stamp Act (16 U.S.C. 718–718j, 48 Stat. 452)]. Additional funding to acquire lands, water, or interests for fish and wildlife conservation purposes could be identified by Congress or donated by nonprofit organizations. The purchase of easements from willing sellers will be subject to available money.

The Service has involved the public, agencies, partners, and legislators throughout the planning process for the easement program. At the beginning of the planning process, the Service initiated public involvement for the proposal to protect habitats primarily through acquisition of wetland and grassland conservation easements for management as part of the Refuge System. The Service spent time discussing the proposed project with landowners; conservation organizations; Federal, State and county governments; tribes and other interested groups and individuals. The Service held three open-house meetings on December 14, 15, and 16, 2010, at Minot, North Dakota; Jamestown, North Dakota; and Huron, South Dakota; respectively. These open houses were announced in local media.

In compliance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321), the Service prepared an environmental assessment (EA) that evaluated two alternatives and their potential impacts on the project area. The Service released the draft environmental assessment (EA) and LPP on June 20, 2011, for a 30-day public review period. The draft documents were made available to Federal elected officials and agencies, State elected officials and agencies, 32 Native American tribes with aboriginal or tribal interests, local media, and other members of the public that were identified during the scoping process.

In addition, two public meetings were held, in Bismarck, North Dakota, and in Miller, South Dakota, on June 28 and 29, 2011, respectively. These meetings were announced in advance in local media. Approximately 50 landowners, citizens, and elected representatives attended the meetings. The Service received 10 letters from agencies, organizations, and other entities, and 347 general public comments. After all comments were received, they were reviewed, added to the administrative record, and incorporated into the environmental assessment (EA) if substantial.

Based on the documentation contained in the environmental assessment (EA), a Finding of No Significant Impact was signed on September 1, 2011, for the establishment of the Dakota Grassland Conservation Area.

Dated: December 2, 2011.

Matt Hogan,

Acting, Deputy Regional Director, Mountain-Prairie Region, U.S. Fish and Wildlife Service.

[FR Doc. 2012–3650 Filed 2–15–12; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

National Indian Gaming Commission

Submission of Information Collection Under the Paperwork Reduction Act; Reinstatement

AGENCY: National Indian Gaming Commission, Interior.

ACTION: Notice.

SUMMARY: The National Indian Gaming Commission (''NIGC'' or ''Commission''), in accordance with the Paperwork Reduction Act, is seeking reinstatement of the approval for collection of information for the following activities: (1) Compliance and enforcement under the Indian Gaming Regulatory Act (''IGRA'' or ''the Act''); (2) approval of Class II background investigation and tribal licenses; (3) management contract regulations; (4) National Environmental Policy Act procedures; (5) annual fees payable by Indian gaming operations; (6) issuance of certificates of self regulation to tribes for Class II gaming; (7) minimum internal control standards; and (8) facility license review. These information collections have expired.

DATES: Submit comments on or before April 16, 2012.

ADDRESSES: Comments can be mailed, faxed, or emailed to the attention of Michael Hoenig, National Indian Gaming Commission, 1441 L Street NW., Washington, DC 20005. Comments may be faxed to (202) 632–7066 (not a toll-free number). Comments may be sent electronically to *info@nigc.gov*, subject: PRA reinstatements.

FOR FURTHER INFORMATION CONTACT: Michael Hoenig at (202) 632–7003; fax (202) 632–7066 (not toll-free numbers).

SUPPLEMENTARY INFORMATION:

I. Request for Comments

You are invited to comment on the following items:

(a) Whether the collections of information are necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burdens (including the hours and cost) of the proposed collections of information, including the validity of the methodologies and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected;

(d) Ways to minimize the burdens of the collections of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other collection techniques or forms of information technology.

Comments submitted in response to this notice will be summarized and become a matter of public record.

II. Data

Title: Compliance and Enforcement.

OMB Control Number: 3141–0001.

Background: IGRA governs the regulation of gaming on Indian lands. Although IGRA places primary responsibility with the tribes for regulating their gaming activity, § 2706(b) directs the NIGC to monitor Class II gaming conducted on Indian lands on a continuing basis. IGRA authorizes the NIGC to access and inspect all papers, books and records relating to gross revenues of Class II gaming conducted on Indian lands and any other matters necessary to carry out the duties of the Commission. IGRA also requires tribes to provide NIGC with annual independent audits of gaming, including contracts in excess of $25,000.00. 25 U.S.C. 2710(b)(2)(c), (d); 25 U.S.C. 2710(d)(1)(A)(ii). In accordance with these statutory responsibilities, NIGC regulations, 25 CFR 571.7, requires Indian gaming operations to keep permanent financial records. NIGC regulations, 25 CFR 571.12 and 571.13, require tribes to annually submit an independent audit of their gaming operations to NIGC. The NIGC uses this information to fulfill its statutory responsibilities under IGRA. Additionally, IGRA, 25 U.S.C. 2713, authorizes the NIGC Chair to issue notices of violation, civil fine assessments, and closure orders for violations of the Act or the Commission's regulations. This authority is implemented through 25 CFR part 575. The full Commission reviews these matters on appeal under 25 CFR part 577.

Brief Description of Collection: This collection is mandatory and allows the NIGC to conduct its statutory duty to regulate Indian gaming. No additional burden is imposed by the requirements to maintain customary business records and to allow NIGC personnel access to those records.

Respondents: Indian tribal gaming operations.

Estimated Number of Respondents: 422.

Estimated Annual Responses: 1,395.

Estimated Time per Response: The range of time can vary from no additional burden hours to 50 burden hours for one item.

Frequency of Responses: Varies.

Estimated Total Annual Burden on Respondents: 6,752.

Title: Approval of Class II and Class III Ordinances, Background Investigations, and Gaming Licenses.

OMB Control Number: 3141–0003.

Background: The Act sets standards for the regulation of gaming, including requirements for approval or disapproval of tribal gaming ordinances. IGRA, § 2705(a)(3), requires the NIGC Chair to review all class II and class III tribal gaming ordinances.

In accordance with this provision, NIGC regulations, 25 CFR 522.2, require tribes to submit to the NIGC: (1) A copy of the gaming ordinance to be approved, including a copy of the authorizing resolution by which it was enacted by the tribal government and a request for approval of the ordinance or resolution; (2) a description of procedures the tribe will employ in conducting background investigations on key employees or primary management officials; (3) a description of procedures the tribe will use to issue licenses to primary management officials and key employees; (4) copies of all gaming regulations; (5) a copy of any applicable tribal-state compact; (6) a description of dispute resolution procedures for disputes arising between the gaming public and the tribe or management contractor; (7) identification of the law enforcement agency that will take fingerprints and a description of the procedures for conducting criminal history checks; and (8) designation of an agent for service of process.

Under NIGC regulations, 25 CFR 522.3, tribes must submit any amendment to the ordinance or resolution for approval by the NIGC Chair. In this instance, the tribe must provide a copy of the authorizing resolution. The NIGC will use the information collected to approve or disapprove the ordinance or amendment.

Section 2710 of the Act requires tribes to conduct background investigations on key employees and primary management officials involved in class II and class III gaming. NIGC regulations, 25 CFR 522.4(b)(4), require a tribe's ordinance to provide that the tribe will perform background investigations and issue licenses for key employees and primary management officials according to requirements that are at least as stringent as those in NIGC regulations, 25 CFR parts 556 and 558. 25 CFR parts 556 and 558 require tribes to perform each investigation using information such as name, address, previous employment records, previous relationships with either Indian tribes or the gaming industry, licensing relating to those relationships, any convictions, and any other information a tribe feels is relevant to the employment of the individuals being investigated. 25 CFR 556.4. Tribes are then required to submit to the NIGC a copy of the completed employment applications and investigative reports and licensing eligibility determinations on key employees or primary management officials before issuing gaming licenses to those persons. 25 CFR 556.5. The NIGC uses this information to review the eligibility and suitability determinations tribes make and advises them if it disagrees with any particular determination.

Brief Description of Collection: This collection is mandatory and allows the NIGC to carry out its statutory duties and gives the respondents standards for compliance.

Respondents: Indian tribal gaming operations.

Estimated Number of Respondents: 282.

Estimated Annual Responses: 112,677.

Estimated Time per Response: The range of time can vary from .5 burden hours to 80 burden hours for one item.

Frequency of Response: Varies.

Estimated Total Annual Burden Hours on Respondents: Up to 36,973 hours.

Title: Management Contract Regulations.

OMB Control Number: 3141–0004.

Background: Subject to the approval of the NIGC Chair, an Indian tribe may enter into a gaming management contract for the operation and management of tribal gaming activity. 25 U.S.C. 2710(e) and 2711. In approving a management contract, the Chair shall require and obtain the following: name, address, and other pertinent background information on each person or entity having a financial interest in, or management responsibility for such contract, and in the case of a corporation those individuals who serve on the board of directors of such corporation and certain stockholders; a description of previous experience that each person has had with other Indian gaming contracts or with the gaming industry including any gaming licenses which the person holds; and a complete financial statement of each person listed. 25 CFR 533.3; 25 CFR 537.1(b).

Under NIGC regulations, 25 CFR part 533, the Chair requires the submission of the contract to contain the following: original signatures; any collateral agreements to the contract; a tribal ordinance or resolution authorizing the submission and supporting documentation; a three-year business plan which sets forth the parties' goals, objectives, budgets, financial plans, related matters, income statements, sources and use of funds statements for the previous three years; and, for any contract exceeding five years or which includes a management fee of more than 30 percent, justification that the capital investment required and income projections for the gaming operation require the longer duration or the additional fee.

Under NIGC regulations, 25 CFR part 535, the Chair may approve a modification to a management contract or an assignment of that management contract based on information similar to that required under part 533. Part 535 also specifies that the Chair may void a previous management contract approval and allows the parties the opportunity to submit information relevant to that determination.

25 CFR part 537 specifies the requirements for submission of background information in amplification of the statutory requirement for obtaining information on persons and entities having a direct financial interest in or management responsibility for a management contract. Finally, 25 CFR part 539 permits appeals to the Commission from a decision of the Chair to disapprove a management contract and allows the Indian tribe and the management company an opportunity to provide information relevant to that appeal. The NIGC will use the information collected to either approve or disapprove the contract or, in the case of an appeal, to grant or deny the appeal.

Brief Description of Collection: This collection is mandatory, and the benefit to the respondents is the approval of Indian gaming management contracts.

Respondents: Tribal governing bodies and management contractors.

Estimated Number of Respondents: 183 (submission of contracts, contract amendments, and background investigation submissions).

Estimated Time per Response: The range of time can vary from no added burden hours to 50 burden hours for one item.

Frequency of Response: Usually no more than once a year.

Estimated Total Annual Hourly Burden to Respondents: Up to 3,890.

Title: NEPA Procedures.

OMB Control Number: 3141–0006.

Background: NEPA requires Federal agencies to analyze proposed major federal actions that significantly affect the quality of the human environment. The NIGC has identified one type of action it undertakes that requires review under NEPA—approving third-party management contracts for the operation of gaming activity under IGRA, 25 U.S.C. 2711. Depending on the nature of the subject contract and other circumstances, approval of such management contracts may be categorically excluded from NEPA, it may require the preparation of an Environmental Assessment (''EA''), or it may require the preparation of an Environmental Impact Statement (''EIS''). In any case, the proponents of a management contract will be expected to submit information to the NIGC and assist in the development of the required NEPA documentation.

Respondents: Tribal governing bodies, management companies, and environmental consultants.

Estimated Number of Respondents: 6 per year.

Estimated Time per Response: The range of time can vary from 1300 to 4500 hours per response. This variation depends on whether the response is an EA or an EIS.

Frequency of Response: Annually.

Estimated Total Annual Burden on Respondents: 12,300 (6 EAs at 1300 hours + 1 EIS at 4500 hours).

Title: Annual Fees Payable by Indian Gaming Operations.

OMB Control Number: 3141–0007.

Background: IGRA requires the NIGC to set an annual funding rate. The annual funding rate is the primary mechanism for NIGC funding under 25 U.S.C. 2717, and NIGC regulations, 25 CFR part 514 implements the requirement. Fees are computed on the basis of the assessable gross revenues of each gaming operation using rates set by the NIGC. The total of all fees assessed annually cannot exceed 0.08 percent of gross gaming revenue. Under its implementing regulation for the fee payment program, 25 CFR part 514, the NIGC relies on a quarterly statement of gross gaming revenues provided by each gaming operation that is subject to the fee requirement. When the Office of Management and Budget last approved the collection of information for annual fees, the NIGC required quarterly submissions of fees and worksheets. Although the Commission later changed part 514 to require biannual submissions of fees and fee worksheets, the Agency has published a final rule in the **Federal Register** restoring the submission requirements to quarterly. That rule goes into effect on October 1, 2012, and the implementation date for quarterly submissions is January 1, 2013. The final rule can be found at 77 FR 5178 and on the NIGC's Web site. The required information is needed for the NIGC to both set and adjust fee rates and to support the computation of fees paid by each gaming operation.

Brief Description of Collection: This collection is mandatory and allows the NIGC to both set and adjust fee rates and to support the computation of fees paid by each gaming operation.

Respondents: Indian tribal gaming operations.

Estimated Number of Respondents: 446.

Estimated Annual Respondents: 892.

Estimated Annual Burden Hours per Respondent: 2 (number of annual responses) × 2 (hours per response) = 4.

Estimated Total Annual Burden on Respondents: 892 (number of responses) × 2 (average hourly burden per response) = 1,784 total annual hours of burden.

Title: Issuance of Certificates of Self-Regulation to Tribes for Class II Gaming.

OMB Control Number: 3141–0008.

Background: IGRA allows any Indian tribe that has conducted class II gaming for at least three years to petition the NIGC for a certificate of self-regulation for its class II gaming operations. The NIGC will issue the certificate if it determines from available information that the tribe has conducted its gaming activity in a manner which has resulted in an effective and honest accounting of all revenues, a reputation for safe, fair, and honest operation of the gaming activity, and an enterprise free of evidence of criminal or dishonest activity. The tribe must also have adopted and implement proper accounting, licensing, and enforcement systems and conducted the gaming operation on a fiscally or economically sound basis. The implementing regulation at 25 CFR part 518 requires a tribe interested in receiving the certificate to file a petition with the NIGC describing, generally, the tribe's gaming operations, its regulatory process, its uses of net gaming revenue, and its accounting and recordkeeping systems for the gaming operation. The tribe must also provide copies of various documents in support of the petition. Submission of the petition and supporting documentation is voluntary. The NIGC will use the information submitted by the respondent tribe in determining whether to issue the certificate of self-regulation.

Those tribes who have been issued a certificate of self-regulation are required to submit annually a report to the NIGC. Such report shall set forth information to establish that the tribe has continuously met the eligibility requirements of 25 CFR 518.2 and the approval requirements of 25 CFR 518.4 and shall include a report with supporting documentation which explains how tribal gaming revenues were used in accordance with the requirements of IGRA, 25 U.S.C. 2710(b)(2)(B).

Brief Description of Collection: This collection is voluntary for those tribes petitioning for a certificate of self-regulation and mandatory for those tribes who hold a certificate of self-regulation according to statutory regulations, and the benefit to the respondents is a reduction of the amount of fees assessed on class II gaming revenue by the NIGC.

Respondents: Tribal governments.

Estimated Number of Voluntary Respondents: 0.

Estimated Time per Voluntary Response: 0.

Frequency of Response: At will.

Estimated Total Annual Hourly Burden to Voluntary Respondents: 0.

Number of Mandatory Respondents: 2.

Estimated Time per Mandatory Response: 50.

Frequency of Mandatory Response: Annual.

Estimated Total Annual Hourly Burden to Mandatory Respondents: 100.

Title: Minimum Internal Control Standards.

OMB Control Number: 3141–0009.

Background: IGRA governs the regulation of gaming on Indian lands. Although the IGRA places primary responsibility with the tribes for regulating Class II gaming, Section 2706(b) of IGRA directs the NIGC to monitor Class II gaming conducted on Indian lands on a continuing basis. IGRA authorizes the NIGC to access and inspect all papers, books and records relating to gross revenues of Class II gaming conducted on Indian lands and any other matters necessary to carry out the duties of the Commission. In accordance with these statutory responsibilities, NIGC regulations require tribal gaming regulatory authorities to establish and implement tribal internal control standards that provide a level of control that equals or exceeds those set out in part 543, establishing internal control standards. NIGC regulations, 25 CFR 543.3 require each affected gaming operation to develop and implement an internal control system that, at a minimum, complies with the tribal internal control standards established by the tribal gaming regulatory authority. Section 543.3(f) requires tribes with gaming operations to engage a certified public accountant (CPA) to perform an agreed-upon-procedures report to confirm compliance with the standards contained therein. The CPA is then required to report its findings to the tribe, tribal gaming regulatory authority, and management.

Brief Description of Collection: Section 543.3(f) requires tribes to submit two copies of the required CPA agreed-upon-procedures report to the Commission. This collection is mandatory for all Class II gaming operations exceeding $1 million in gross gaming revenue and many Class III facilities and smaller gaming operations choose to submit it voluntarily. Because the report is outsourced, minimal additional time burden is imposed by the requirement.

Estimated Number of Respondents: 422.

Estimated Time per Response: 0.5 hours.

Frequency of Response: Annually.

Estimated Total Annual Hourly Burden to Respondents: 211 hours (422 responses × 0.5 hour per response).

Title: Facility License Standards.

OMB Control Number: 3141–0012.

Background: IGRA states that ''a separate license issued by the Indian tribe shall be required for each place, facility, or location on Indian lands at which class II [and class III] gaming is conducted.'' 25 U.S.C. 2710(b)(1) and (d)(1)(A)(iii). Further, IGRA requires ''the construction and maintenance of the gaming facilities, and the operation of that gaming is conducted in a manner which adequately protects the environment and public health and safety.'' 25 U.S.C. 2710(b)(2)(E).

NIGC regulations, part 559 requires that a tribe submit a notice to the NIGC that it is considering issuing a facility license, including applicable Indian lands information, at least 120 days before a new class II and/or class III gaming facility is opened. The amount of Indian lands information depends, in part, on whether the Bureau of Indian Affairs maintains the necessary records. The Indian lands information will continue to be utilized by the NIGC to ensure that its records are complete for internal purposes, such as assessing the NIGC's jurisdiction to regulate the gaming on the parcel, as well as responding to inquiries from government agencies and Congress as to the statuses of lands where Indian gaming is proposed or occurring.

Part 559 also requires that tribes submit copies of each newly issued or renewed facility license to the NIGC within 30 days of issuance, as well as notices of facility closures. This information will enable the NIGC to maintain accurate, up-to-date records of the Indian gaming facilities that are operating on Indian lands in the United States at any given point in time. Currently, facility licenses must be renewed every three years. With each new facility license, the Tribe must submit an attestation that it has identified and enforces environment and public health and safety laws and that the tribe is in compliance with those laws. Part 559 also requires tribes to submit a document listing all environmental and public safety laws, resolutions, codes, policies and standards applicable to its gaming facility. If the submitted laws, resolutions, etc. do not change, the tribe need only certify that fact when submitting a renewed facility license. Finally, the NIGC Chair has the discretion to request environmental and public health and safety documentation on occasions when there is an identified, substantial concern. Through these submissions, the NIGC can ensure that the tribes have determined that the construction, maintenance, and operation of their gaming facilities are conducted in a manner that adequately protects the environment and the public health and safety.

This information collection serves two purposes: (i) to receive up-to-date information from tribes regarding the number of licensed Indian gaming facilities and the Indian lands status of the site of each gaming facility; and (ii) to obtain certifications from the tribes that the construction, maintenance, and operation of the gaming facilities are conducted in a manner that adequately protects the environment and the public health and safety.

Brief Description of Collection: This collection is mandatory and enables the NIGC to conduct its statutory duty to regulate Indian gaming by ensuring that tribal gaming facilities are properly licensed by the tribes.

Respondents: Indian tribal gaming operations.

Estimated Number of Respondents: 565.

Estimated Annual Responses: 75.

Estimated Time per Response: The range of time can vary from 2 burden hours to 10 burden hours for one item.

Frequency of Response: Varies.

Estimated Total Annual Burden on Respondents: $13,125.

Dated: February 13, 2012.

Paxton Myers,

Chief of Staff.

[FR Doc. 2012–3689 Filed 2–15–12; 8:45 am]

BILLING CODE 7565–01–P

DEPARTMENT OF THE INTERIOR

Bureau of Reclamation

Agency Information Collection; Renewal of a Currently Approved Information Collection

AGENCY: Bureau of Reclamation, Interior.

ACTION: Notice and request for comments.

SUMMARY: The Bureau of Reclamation intends to seek an extension of the information collection for the Lower Colorado River Well Inventory (1006–0014). The current OMB approval expires on May 31, 2012.

DATES: Submit comments on this notice by April 16, 2012.

ADDRESSES: Send all written comments concerning this notice to Paul Matuska, Water Accounting and Verification Group Manager, LC–4200, Bureau of Reclamation, Lower Colorado Regional Office, P.O. Box 61470, Boulder City, NV 89006–1470; or by email to *pmatuska@usbr.gov.*

FOR FURTHER INFORMATION CONTACT: Paul Matuska, Water Accounting and Verification Group Manager, Bureau of Reclamation, Lower Colorado Regional Office, 702–293–8164.

SUPPLEMENTARY INFORMATION: In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.), this notice announces that the Bureau of Reclamation is requesting approval for the collection of data from well and river-pump owners and operators along the lower Colorado River in Arizona, California, and Nevada.

Title: Lower Colorado River Well Inventory.

OMB Control Number: 1006–0014.

Abstract: Pursuant to the Boulder Canyon Project Act (Pub. L. 70–642, 45 Stat. 1057), all diversions of mainstream Colorado River water must be in accordance with a Colorado River water entitlement. The Consolidated Decree of the United States Supreme Court in *Arizona* v. *California,* 547 U.S. 150 (2006) requires the Secretary of the Interior to account for all diversions of mainstream Colorado River water along the lower Colorado River, including water drawn from the mainstream by underground pumping. To meet the water entitlement and accounting obligations, an inventory of wells and river pumps is required along the lower Colorado River, and the gathering of specific information concerning these wells.

Description of respondents: The respondents will include well and river-pump owners and operators along the lower Colorado River in Arizona, California, and Nevada. Each diverter (including well pumpers) must be identified and their diversion locations and water use determined.

Frequency: These data are collected only once for each well or river-pump owner or operator as long as changes in water use, or other changes that would impact contractual or administrative requirements, are not made. A respondent may request that the data for its well or river pump be updated after the initial inventory.

Estimated completion time: An average of 20 minutes is required to interview individual well and river-pump owners or operators. Reclamation will use the information collected during these interviews to complete the information collection form.

Estimated Total Number of Respondents: 1,500.

Estimated Number of Responses per Respondent: 1.0.

Estimated Total of Annual Responses: 1,500.

Estimated Total Annual Burden Hours on Respondents: 500 hours.

Comments

Comments are invited on:

(a) Whether the proposed collection of information is necessary for the proper performance of our functions, including whether the information will have practical use;

(b) The accuracy of our burden estimate for the proposed collection of information;

(c) Ways to enhance the quality, usefulness, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

We will summarize all comments received regarding this notice. We will publish that summary in the **Federal Register** when the information collection request is submitted to OMB for review and approval.

Public Disclosure

Before including your address, telephone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Dated: February 10, 2012.

Terrance J. Fulp,

Acting Regional Director, Lower Colorado Region, Bureau of Reclamation.

[FR Doc. 2012–3649 Filed 2–15–12; 8:45 am]

BILLING CODE 4310–MN–P

DEPARTMENT OF THE INTERIOR

Bureau of Reclamation

Glen Canyon Dam Adaptive Management Work Group

AGENCY: Bureau of Reclamation, Interior.

ACTION: Notice of public meeting.

SUMMARY: The Glen Canyon Dam Adaptive Management Work Group (AMWG) makes recommendations to the Secretary of the Interior concerning Glen Canyon Dam operations and other management actions to protect resources downstream of Glen Canyon Dam, consistent with the Grand Canyon Protection Act. The AMWG meets two to three times a year.

DATES: The meeting will be held on Wednesday, February 22, 2012, from 9:30 a.m. to approximately 5:30 p.m., and Thursday, February 23, 2012, from 8 a.m. to approximately 3 p.m.

ADDRESSES: The meeting will be held at the Fiesta Resort Conference Center, 2100 S. Priest Drive, Tempe, Arizona.

FOR FURTHER INFORMATION CONTACT: Glen Knowles, Bureau of Reclamation, telephone (801) 524–3781; facsimile (801) 524–3858; email at *gknowles@usbr.gov.*

SUPPLEMENTARY INFORMATION: The Glen Canyon Dam Adaptive Management Program (AMP) was implemented as a result of the Record of Decision on the Operation of Glen Canyon Dam Final Environmental Impact Statement to comply with consultation requirements of the Grand Canyon Protection Act (Pub. L. 102–575) of 1992. The AMP includes a Federal advisory committee, the AMWG, a technical work group (TWG), a Grand Canyon Monitoring and Research Center, and independent review panels. The TWG is a subcommittee of the AMWG and provides technical advice and recommendations to the AMWG.

Agenda: The primary purpose of the meeting will be for the AMWG to begin discussions on the Fiscal Year 2013–2014 budget and hydrograph, receive updates on the two environmental assessments being prepared by the Bureau of Reclamation, the Long Term Experimental and Management Plan environmental impact statement, current basin hydrology and Glen Canyon Dam operational changes, project updates from the Grand Canyon Monitoring and Research Center, and an update from the Desired Future Conditions Ad Hoc Group. The AMWG will also address other administrative and resource issues pertaining to the AMP.

To view a copy of the agenda and documents related to the above meeting, please visit Reclamation's Web site at *http://www.usbr.gov/uc/rm/amp/amwg/mtgs/12feb22.html.* Time will be allowed at the meeting for any individual or organization wishing to make formal oral comments. To allow for full consideration of information by the AMWG members, written notice must be provided to Glen Knowles, Bureau of Reclamation, Upper Colorado Regional Office, 125 South State Street, Room 6107, Salt Lake City, Utah 84138; telephone 801–524–3781; facsimile 801–524–3858; email at *gknowles@usbr.gov* at least five (5) days prior to the meeting. Any written comments received will be provided to the AMWG members.

Public Disclosure of Comments

Before including your name, address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Dated: January 17, 2012.

Glen Knowles,

Chief, Adaptive Management Group, Environmental Resources Division, Upper Colorado Regional Office, Salt Lake City, Utah.

[FR Doc. 2012–3651 Filed 2–15–12; 8:45 am]

BILLING CODE 4310–MN–P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—PXI Systems Alliance, Inc.

Notice is hereby given that, on January 26, 2012, pursuant to Section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), PXI Systems Alliance, Inc. has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Logic Instruments S.A., Domont, France, has been added as a party to this venture. Also, Averna, Montreal, Quebec, Canada; and Hunan RunCore High-Tech Co. Ltd., Chang Sha, Hunan, People's Republic of China, have withdrawn as parties to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and PXI Systems Alliance, Inc. intends to file additional written notifications disclosing all changes in membership.

On November 22, 2000, PXI Systems Alliance, Inc. filed its original notification pursuant to Section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to Section 6(b) of the Act on March 8, 2001 (66 FR 13971).

The last notification was filed with the Department on November 22, 2011. A notice was published in the **Federal Register** pursuant to Section 6(b) of the Act on December 23, 2011 (76 FR 80405).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2012–3684 Filed 2–15–12; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—ODVA, Inc.

Notice is hereby given that, on January 27, 2012, pursuant to Section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), ODVA, Inc. (''ODVA'') has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, SKF USA Inc., Landsdale, PA; Precision Engine Controls Corporation, San Diego, CA; Altronic, LLC, Girard, OH; Sierra Instruments, Inc., Monterey, CA; and Trebing & Himstedt ProzeBautomation GmbH & Co. KG, Schwerin, Germany, have been added as parties to this venture.

Also, Q-Lambda, Lund, Sweden; Exlar Corporation, Chanhassen, MN; Spang Power Electronics, Mentor, OH; and ASCO Pneumatic Controls, Florham Park, NJ, have withdrawn as parties to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and ODVA intends to file additional written notifications disclosing all changes in membership.

On June 21, 1995, ODVA filed its original notification pursuant to Section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to Section 6(b) of the Act on February 15, 1996 (61 FR 6039).

The last notification was filed with the Department on November 1, 2011. A notice was published in the **Federal Register** pursuant to Section 6(b) of the Act on December 12, 2011 (76 FR 77250).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2012–3691 Filed 2–15–12; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Pistoia Alliance, Inc.

Notice is hereby given that, on January 27, 2012, pursuant to Section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Pistoia Alliance, Inc. has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, Johnson & Johnson Research and Development LLC, San Diego, CA; Unilever (UK) Central Resources Limited, London, United Kingdom; Ian Harrow Consulting Limited, Whitstable, Kent, United Kingdom; Alex M. Clark (Individual), Montreal, Quebec, Canada; and Parthys Reverse Informatics Analytic Solutions (P) Ltd., Chennai, Tamilnadu, India, have been added as parties to this venture. Also, Ariadne Genomics, Rockville, MD, has withdrawn as a party to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and Pistoia Alliance, Inc. intends to file additional written notifications disclosing all changes in membership.

On May 28, 2009, Pistoia Alliance, Inc. filed its original notification pursuant to Section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to Section 6(b) of the Act on July 15, 2009 (74 FR 34364).

The last notification was filed with the Department on November 3, 2011. A notice was published in the **Federal Register** pursuant to Section 6(b) of the Act on December 15, 2011 (76 FR 78043).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2012–3693 Filed 2–15–12; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Antitrust Division

Notice Pursuant to the National Cooperative Research and Production Act of 1993—Interchangeable Virtual Instruments Foundation, Inc.

Notice is hereby given that, on January 26, 2012, pursuant to Section 6(a) of the National Cooperative Research and Production Act of 1993, 15 U.S.C. 4301 *et seq.* (''the Act''), Interchangeable Virtual Instruments Foundation, Inc. has filed written notifications simultaneously with the Attorney General and the Federal Trade Commission disclosing changes in its membership. The notifications were filed for the purpose of extending the Act's provisions limiting the recovery of antitrust plaintiffs to actual damages under specified circumstances. Specifically, C&H Technologies, Inc., Round Rock, TX; and Nokia, Frederikskaj, Copenhagen, Denmark, have withdrawn as parties to this venture.

No other changes have been made in either the membership or planned activity of the group research project. Membership in this group research project remains open, and Interchangeable Virtual Instruments Foundation, Inc. intends to file additional written notifications disclosing all changes in membership.

On May 29, 2001, Interchangeable Virtual Instruments Foundation, Inc. filed its original notification pursuant to Section 6(a) of the Act. The Department of Justice published a notice in the **Federal Register** pursuant to Section 6(b) of the Act on July 30, 2001 (66 FR 39336).

The last notification was filed with the Department on November 22, 2011. A notice was published in the **Federal Register** pursuant to Section 6(b) of the Act on December 23, 2011 (76 FR 80405).

Patricia A. Brink,

Director of Civil Enforcement, Antitrust Division.

[FR Doc. 2012–3686 Filed 2–15–12; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Foreign Claims Settlement Commission

Sunshine Act Meeting

F.C.S.C. Meeting and Hearing Notice No. 02–12

The Foreign Claims Settlement Commission, pursuant to its regulations (45 CFR part 503.25) and the Government in the Sunshine Act (5 U.S.C. 552b), hereby gives notice in regard to the scheduling of open meetings as follows:

Thursday, February 23, 2012:

3:00 p.m.—Issuance of Proposed Decisions in claims against Libya.

4:00 p.m.—Oral hearing on Objection to Commission's Proposed Decision in Claim No. LIB–II–088.

Friday, February 24, 2012:

9:00 a.m.—Oral hearings on Objection to Commission's Proposed Decisions in Claim No. LIB–I–051; 10:30 a.m.—LIB–II–169; 12:00 NOON—LIB–II–178.

Status: Open.

All meetings are held at the Foreign Claims Settlement Commission, 600 E Street NW., Washington, DC. Requests for information, or advance notices of intention to observe an open meeting, may be directed to: Judith H. Lock, Executive Officer, Foreign Claims Settlement Commission, 600 E Street NW., Suite 6002, Washington, DC 20579. Telephone: (202) 616–6975.

Jaleh F. Barrett,

Chief Counsel.

[FR Doc. 2012–3843 Filed 2–14–12; 4:15 pm]

BILLING CODE 4410–BA–P

DEPARTMENT OF LABOR

Child Labor, Forced Labor, and Forced or Indentured Child Labor in the Production of Goods in Foreign Countries and Efforts by Certain Countries To Eliminate the Worst Forms of Child Labor

AGENCY: The Bureau of International Labor Affairs, United States Department of Labor.

ACTION: Notice: Request for information and invitation to comment.

SUMMARY: This notice is a request for information and/or comment on reports issued by the Bureau of International Labor Affairs (ILAB) October 3, 2011, regarding child labor and forced labor in foreign countries. Relevant information will be used by the Department of Labor (DOL) in preparation of its ongoing reporting under Congressional mandates and Presidential directive. In addition, ILAB may use relevant information to conduct assessments of each country's individual progress towards eliminating the worst forms of child labor during the current reporting period compared to previous years.

DATES: Submitters of information are requested to provide their submission to the Office of Child Labor, Forced Labor and Human Trafficking (OCFT) at the email or physical address below by 5 p.m. March 9, 2012.

To Submit Information: Information submitted to DOL should be submitted directly to OCFT, Bureau of International Labor Affairs, U.S. Department of Labor at (202) 693–4843 (this is not a toll free number). Comments, identified as ''Docket No. DOL–2011–0002,'' may be submitted by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.*

The portal includes instructions for submitting comments. Parties submitting responses electronically are encouraged not to submit paper copies.

- *Facsimile (fax):* OCFT at 202–693–4830.
- *Mail, Express Delivery, Hand Delivery, and Messenger Service (2 copies):* Tina McCarter at U.S. Department of Labor, OCFT, Bureau of International Labor Affairs, 200 Constitution Avenue NW., Room S–5317, Washington, DC 20210.
- *Email:* Email submissions should be addressed to Tina McCarter at *mccarter.tina@dol.gov.*

FOR FURTHER INFORMATION CONTACT: Tina McCarter (see contact information above).

SUPPLEMENTARY INFORMATION:

I. Section 105(b)(1) of the Trafficking Victims Protection Reauthorization Act of 2005 (''TVPRA of 2005''), Public Law 109–164 (2006), directed the Secretary of Labor, acting through ILAB, to ''develop and make available to the public a list of goods from countries that the Bureau of International Labor Affairs has reason to believe are produced by forced labor or child labor in violation of international standards'' (TVPRA List).

Pursuant to this mandate, in December 2007 DOL published in the **Federal Register** a set of procedural guidelines that ILAB follows in developing the TVPRA List (72 FR 73374). The guidelines set forth the criteria by which information is evaluated; established procedures for public submission of information to be considered by ILAB; and identified the process ILAB follows in maintaining and updating the List after its initial publication.

ILAB released its first TVPRA List on September 30, 2009, an update on December 10, 2010 and another update on October 3, 2011. This List is updated periodically as additional countries and territories are researched and new information for countries and territories already reviewed is evaluated. For a copy of the 2011 TVPRA report, Frequently Asked Questions, and other materials relating to the TVPRA List, see ILAB's TVPRA Web page at: *http://www.dol.gov/ILAB/programs/ocft/tvpra.htm.*

II. Executive Order No. 13126 (E.O. 13126) declared that it was ''the policy of the United States Government * * * that the executive agencies shall take appropriate actions to enforce the laws prohibiting the manufacture or importation of goods, wares, articles, and merchandise mined, produced, or manufactured wholly or in part by forced or indentured child labor.'' Pursuant to E.O. 13126, and following public notice and comment, the Department of Labor published in the January 18, 2001, **Federal Register**, a final list of products (''E.O. List''), identified by country of origin, that the Department, in consultation and cooperation with the Departments of State (DOS) and Treasury [relevant responsibilities now within the Department of Homeland Security (DHS)], had a reasonable basis to believe might have been mined, produced or manufactured with forced or indentured child labor (66 FR 5353). In addition to the List, the Department also published on January 18, 2001, ''Procedural Guidelines for Maintenance of the List of Products Requiring Federal Contractor Certification as to Forced or Indentured Child Labor,'' which provide for maintaining, reviewing, and, as appropriate, revising the EO List (66 FR 5351).

Pursuant to Sections D through G of the Procedural Guidelines, the EO List may be updated through consideration of submissions by individuals or through OCFT's own initiative.

DOL has officially revised the EO List twice, on July 20, 2010 and May 31, 2011, each time after public notice and comment as well as consultation with DOS and DHS. In addition, DOL published an initial determination on October 4, 2011 proposing another revision to the EO List and requesting public comment (76 FR 61384).

The current EO List, Procedural Guidelines, and related information can be accessed on the Internet at *http://www.dol.gov/ILAB/regs/eo13126/main.htm.*

III. The Trade and Development Act of 2000 (TDA), Public Law 106–200 (2002), established a new eligibility criterion for receipt of trade benefits under the Generalized System of Preferences (GSP), Caribbean Basin Trade and Partnership Act (CBTPA), and Africa Growth and Opportunity Act (AGOA). The TDA amends the GSP reporting requirements of Section 504 of the Trade Act of 1974, 19 U.S.C. 2464, to require that the President's annual report on the status of internationally recognized worker rights include ''findings by the Secretary of Labor with respect to the beneficiary country's implementation of its international commitments to eliminate the worst forms of child labor.'' Title II of the TDA and the TDA Conference Report, Joint Explanatory Statement of the Committee of Conference, 106th Cong.2d.Sess. (2000), indicate that the same criterion applies for the receipt of benefits under CBTPA and AGOA, respectively.

In addition, the Andean Trade Preference Act, as amended and expanded by the Andean Trade Promotion and Drug Eradication Act, Public Law 107–210, Title XXXI (2002), includes as a criterion for receiving benefits ''[w]hether the country has implemented its commitments to eliminate the worst forms of child labor as defined in section 507(6) of the Trade Act of 1974.'' DOL fulfills these reporting mandates through annual publication of the U.S. Department of Labor's Findings on the Worst Forms of Child Labor with respect to countries eligible for the aforementioned programs. The 2010 report and additional background information are available on the Internet at *http://www.dol.gov/ILAB/programs/ocft/tda.htm.*

Information Requested and Invitation To Comment: Interested parties are invited to comment and provide information regarding DOL's 2010 TDA Report; the 2011 TVPRA list; and the current E.O. 13126 List, all of which may be found on the Internet at *http://www.dol.gov/ilab/programs/ocft/research.htm* or obtained from OCFT. DOL requests comments or information to update the findings and suggestions for government action for countries reviewed in the TDA report, as well as to assess each country's individual progress towards eliminating the worst forms of child labor during the current reporting period compared to previous years. In addition, DOL especially appreciates information on the nature and extent of child labor, forced labor, and forced or indentured child labor in the production of goods in foreign countries as well as information on government, industry, or third-party actions to address these issues for countries reviewed for the E.O. and TVPRA lists. Materials submitted should be confined to the specific topics of these reports. DOL will generally consider sources with dates up to five years old (i.e., data not older than January 1, 2006). DOL appreciates the extent to which submissions clearly indicate the time period to which they apply. In the interest of transparency, classified information will not be accepted. Where applicable, information submitted should indicate its source or sources, and copies of the source material should be provided. If primary sources are utilized, such as research studies, interviews, direct observations, or other sources of quantitative or qualitative data, details on the research or data-gathering methodology should be provided. Please see the 2010 TDA Report, TVPRA List, and E.O. List for a complete explanation of relevant terms, definitions, and reporting guidelines employed by DOL, or refer to ILAB's previous Request for Information published in the **Federal Register** on April 25, 2011 (76 FR 22921).

This notice is a general solicitation of comments from the public.

Signed at Washington, DC, this 9th day of February 2012.

Sandra Polaski,

Deputy Undersecretary for International Labor Affairs.

[FR Doc. 2012–3592 Filed 2–15–12; 8:45 am]

BILLING CODE 4510–28–P

DEPARTMENT OF LABOR

Mine Safety and Health Administration

Petitions for Modification of Application of Existing Mandatory Safety Standards

AGENCY: Mine Safety and Health Administration, Labor.

ACTION: Notice.

SUMMARY: Section 101(c) of the Federal Mine Safety and Health Act of 1977 and 30 CFR Part 44 govern the application, processing, and disposition of petitions for modification. This notice is a summary of petitions for modification submitted to the Mine Safety and Health Administration (MSHA) by the parties listed below to modify the application of existing mandatory safety standards codified in Title 30 of the Code of Federal Regulations.

DATES: All comments on the petitions must be received by the Office of Standards, Regulations, and Variances on or before March 19, 2012.

ADDRESSES: You may submit your comments, identified by ''docket number'' on the subject line, by any of the following methods:

1. *Electronic Mail: zzMSHA-comments@dol.gov*. Include the docket number of the petition in the subject line of the message.

2. *Facsimile:* 202–693–9441.

3. *Regular Mail:* MSHA, Office of Standards, Regulations, and Variances, 1100 Wilson Boulevard, Room 2350, Arlington, Virginia 22209–3939, Attention: Roslyn B. Fontaine, Acting Director, Office of Standards, Regulations, and Variances.

4. *Hand-Delivery or Courier:* MSHA, Office of Standards, Regulations, and Variances, 1100 Wilson Boulevard, Room 2350, Arlington, Virginia 22209–3939. Individuals who submit comments by hand-delivery are required to check in at the receptionist's desk on the 21st floor. Individuals may inspect copies of the petitions and comments during normal business hours at the address listed above.

MSHA will consider only comments postmarked by the U.S. Postal Service or proof of delivery from another delivery service such as UPS or Federal Express on or before the deadline for comments.

FOR FURTHER INFORMATION CONTACT: Barbara Barron, Office of Standards, Regulations, and Variances at 202–693–9447 (Voice), *barron.barbara@dol.gov* (E-mail), or 202–693–9441 (Facsimile). [These are not toll-free numbers].

SUPPLEMENTARY INFORMATION:

I. Background

Section 101(c) of the Federal Mine Safety and Health Act of 1977 (Mine Act) allows the mine operator or representative of miners to file a petition to modify the application of any mandatory safety standard to a coal or other mine if the Secretary of Labor determines that:

(1) An alternative method of achieving the result of such standard exists which will at all times guarantee no less than the same measure of protection afforded the miners of such mine by such standard; or

(2) That the application of such standard to such mine will result in a diminution of safety to the miners in such mine.

In addition, the regulations at 30 CFR 44.10 and 44.11 establish the requirements and procedures for filing petitions for modification.

II. Petitions for Modification

Docket Number: M–2011–044–C.

Petitioner: Bowie Resources, LLC, P.O. Box 1488, Paonia, Colorado 81418.

Mine: Bowie No. 2 Mine, MSHA I.D. No. 05–04591, P.O. Box 1488, Paonia, Colorado 81418, located in Delta County, Colorado.

Regulation Affected: 30 CFR 75.500(d) (Permissible electric equipment).

Modification Request: The petitioner requests a modification of the existing standard to permit an alternative method of compliance to permit the use of batter-powered non-permissible surveying equipment in or inby the last open crosscut, including in the return airways. The petitioner states that:

(1) Equivalent permissible equipment does not exist.

(2) Equivalent non-electronic surveying equipment is obsolete technology and new replacement equipment does not exist; replacement parts and reconditioned equipment are becoming increasingly unavailable.

(3) The continued use of obsolete and worn or reconditioned equipment that may be inaccurate will result in a diminution of safety in that surveys will become increasingly inaccurate which could result in:

(a) The development of entries that are not straight and true.

(b) Pillar sizes that may become compromised.

(c) The location of mine workings that may be inaccurate, creating reduced barrier pillar sizes when approaching old workings and outcrops.

(4) In the alternative to compliance with the existing standard, the petitioner proposes the following:

(a) Non-permissible surveying equipment will be used only when equivalent permissible equipment does not exist.

(b) All non-permissible surveying equipment will be limited to:

(i) Topcon Electronic Total Station Model GTS–233W 7.2 volts d.c.

(ii) Topcon Electronic Total Station Model GTS–235W 7.2 volts d.c.

(iii) Topcon Electronic Total Station Model GTS–211D 7.2 volts d.c.

(iv) Nikon Total Station Nivo Series Model Nivo 2.C 3.8 volts d.c.

(v) Nikon DTM–302 Series Model DTM–352 7.2 volts d.c.

(vi) Spectra Precision Nomad Data Collector 5.0 volts d.c.

(vii) Equivalent equipment with equal or lower voltages.

(c) All non-permissible surveying equipment used in or inby the last open crosscut or in a return airway will be examined by a qualified person, as defined in 30 CFR 75.153, at least weekly to ensure that the equipment is being maintained in a safe operating condition. The results of the inspection will be recorded and the record will be retained for one year and made available for review by MSHA upon request.

(d) All non-permissible surveying equipment to be used in or inby the last open crosscut or in a return airway will be examined in fresh air outby the last open crosscut prior to being used to ensure that the equipment is being maintained in a safe operating condition. The examination will include:

(i) Checking the instrument for any physical damage and the integrity of the case.

(ii) Powering-up and shutting-down the instrument to ensure proper operation.

(iii) Checking the battery compartment cover to ensure that it is securely fastened.

(e) A qualified person, as defined in 30 CFR 75.151, will continuously monitor for methane immediately before and during the use of non-permissible surveying equipment in or inby the last open crosscut or in a return airway.

(f) Non-permissible surveying equipment will not be used if methane is detected at or above 1.0 percent. When 1.0 percent or more methane is detected while the non-permissible surveying equipment is being used, the equipment will be deenergized immediately and withdrawn outby the last open crosscut or out of a return airway.

(g) All hand-held methane detectors will be MSHA-approved and maintained in permissible and proper operating condition as defined in 30 CFR 75.320.

(h) Non-permissible surveying equipment will not be used when coal production is occurring in the entry being surveyed unless it is necessary for the surveying.

(i) Batteries contained in the non-permissible surveying equipment will be changed out or charged in intake air outby the last open crosscut.

(j) Personnel who use the non-permissible surveying equipment will be trained to recognize the hazards and limitations associated with its use.

(k) The non-permissible surveying equipment will not be put into service until MSHA has initially inspected the equipment and determined that it is in compliance with all of the terms and conditions in this petition.

(l) Within 60 days after this petition becomes final, the petitioner will submit proposed revisions for its approved 30 CFR part 48 training plan to the District Manager. The revisions will specify initial and refresher training regarding the terms and conditions in this petition.

The petitioner asserts that the proposed alternative method will at all times guarantee no less than the same measure of protection as that afforded by the existing standard.

Docket Number: M–2011–045–C.

Petitioner: Alpha Engineering Services, Inc., 216 Business Street, Beckley, West Virginia 25801.

Mines: Signature Mining, Coalburg No. 1 Mine, MSHA I.D. No. 46–09082, and Newtown Energy, Coalburg No. 1 Mine, MSHA I.D. No. 46–08993, and Patriot Coal, Harris No. 1 Mine, MSHA I.D. No. 46–01271, and Newtown Energy, Peerless Rachel Mine, MSHA I.D. No. 46–09258, located in Boone County, West Virginia; Arch-Wolf Run, Sentinel Mine, MSHA I.D. No. 46–04168, located in Barbour County, West Virginia; Arch-Wolf Run, Imperial Mine, MSHA I.D. No. 46–09115, and Arch-Wolf Run, Sago Mine, MSHA I.D. No. 46–08791, located in Upshur County, West Virginia; Arch-Wolf Run, Sycamore 2 Mine, MSHA I.D. No. 46–09060, located in Harrison County, West Virginia; Arch-Tygart Valley LLC, Tygart No. 1 Mine, MSHA I.D. No. 46–09192, located in Taylor County, West Virginia; Arch-Beckley LLC, Beckley Pocahontas Mine, MSHA I.D. No. 46–09216, and Performance Coal Co., Upper Big Branch Mine, MSHA I.D. No. 46–08436, located in Raleigh County, West Virginia; Newtown Energy, Eagle Mine, MSHA I.D. No. 46–08759, and Newtown Energy, Coalburg No. 2 Mine, MSHA I.D. No. 46–09231, and Speed Mining LLC, American Eagle Mine, MSHA I.D. No. 46–05437, located in Kanawha County, West Virginia; Prairie State, Lively Grove Mine, MSHA I.D. No. 11–03193, located in Washington County, Illinois; Pinnacle Mining, Pinnacle Mine, MSHA I.D. No. 46–01816, located in Wyoming County, West Virginia.

Regulation Affected: 30 CFR 75.500(d) (Permissible electric equipment).

Modification Request: The petitioner requests a modification of the existing standard to permit the use of battery-powered non-permissible surveying equipment in and inby the last open cross-cut, including, but not limited to, portable battery-operated mine transits, total station surveying equipment, distance meters, and laptop computers. The petitioner proposes to use up-to-date, practical, and accurate technology in the preparation of mine maps to ensure the safety of the miners by providing proper and accurate mining directional control in the mine. The petitioner states that:

(1) Application of the existing standard would result in a diminution of safety to the miners.

(2) Underground mining, by its nature, size, complexity, and relative closeness to other abandoned mines, gas/oil wells, and other features,

requires that accurate and precise measurements be completed in a prompt and efficient manner.

(3) The use of currently available non-electronic equipment is less accurate and less dependable than the available electronic equipment and requires more exposure of surveyors to hazardous mining environments. As an alternative to compliance with the existing standard, the petitioner proposes the following:

(a) To examine all non-permissible electronic surveying equipment prior to use in or inby the last open crosscut to ensure that the equipment is being maintained in a safe operating condition, and have a qualified person, as defined in 30 CFR 75.153, examine the equipment at intervals not to exceed 7 days. The examination results will be recorded in the weekly examination of electrical equipment book. The examinations will include:

(i) Checks of the instrument for any physical damage and the integrity of the case.

(ii) Removal of the battery and an inspection for corrosion and damage.

(iii) Inspection of the contact points to ensure a secure connection to the battery.

(iv) Reinsertion of the battery and a power-up and shut-down of the instrument to ensure proper connections.

(v) Checks of the battery compartment cover to ensure that it is securely fastened.

(b) A qualified person, as defined in 30 CFR 75.151, will continuously monitor for methane immediately before and during the use of non-permissible surveying equipment in or inby the last open crosscut or in the return.

(c) Non-permissible surveying equipment will not be used if methane is detected in concentrations at or above 1.0 percent. When 1.0 percent or more of methane is detected while the non-permissible surveying equipment is being used, the equipment will be deenergized immediately and the non-permissible electronic equipment will be withdrawn out of the return.

(d) Non-permissible surveying equipment will not be used in areas where float coal dust is in suspension.

(e) Batteries contained in the surveying equipment will be changed out or charged in fresh air and not in the return.

(f) Qualified personnel who use the surveying equipment will be properly trained to recognize the hazards and limitations associated with the use of non-permissible surveying equipment.

(g) The non-permissible surveying equipment will not be put into service until MSHA has initially inspected the equipment and determined that it is in compliance with the terms and conditions in this petition.

(h) Within 60 days after the Proposed Decision and Order becomes final, the petitioner will submit proposed revisions for its approved 30 CFR Part 48 training plan to the District Manager. These proposed revisions will specify initial and refresher training regarding the terms and conditions stated in the Proposed Decision and Order.

The petitioner further states that the nature of work at times will require that surveying services that would be covered by this petition be provided on short notice and, therefore, does not want the petitions to apply to specific companies or mines. The petitioner states that the list of companies and mines in this petition is not all-inclusive.

The petitioner asserts that the proposed alternative method will at all times guarantee no less than the same measure of protection afforded by the existing standard.

Docket Number: M–2011–046–C.

Petitioner: Alpha Engineering Services, Inc., 216 Business Street, Beckley, West Virginia 25801.

Mines: Signature Mining, Coalburg No. 1 Mine, MSHA I.D. No. 46–09082, and Newtown Energy, Coalburg No. 1 Mine, MSHA I.D. No. 46–08993, and Patriot Coal, Harris No. 1 Mine, MSHA I.D. No. 46–01271, and Newtown Energy, Peerless Rachel Mine, MSHA I.D. No. 46–09258, located in Boone County, West Virginia; Arch-Wolf Run, Sentinel Mine, MSHA I.D. No. 46–04168, located in Barbour County, West Virginia; Arch-Wolf Run, Imperial Mine, MSHA I.D. No. 46–09115, and Arch-Wolf Run, Sago Mine, MSHA I.D. No. 46–08791, located in Upshur County, West Virginia; Arch-Wolf Run, Sycamore 2 Mine, MSHA I.D. No. 46–09060, located in Harrison County, West Virginia; Arch-Tygart Valley LLC, Tygart No. 1 Mine, MSHA I.D. No. 46–09192, located in Taylor County, West Virginia; Arch-Beckley LLC, Beckley Pocahontas Mine, MSHA I.D. No. 46–09216, and Performance Coal Co., Upper Big Branch Mine, MSHA I.D. No. 46–08436, located in Raleigh County, West Virginia; Newtown Energy, Eagle Mine, MSHA I.D. No. 46–08759, and Newtown Energy, Coalburg No. 2 Mine, MSHA I.D. No. 46–09231, and Speed Mining LLC, American Eagle Mine, MSHA I.D. No. 46–05437, located in Kanawha County, West Virginia; Prairie State, Lively Grove Mine, MSHA I.D. No. 11–03193, located in Washington County, Illinois; Pinnacle Mining, Pinnacle Mine, MSHA I.D. No. 46–01816, located in Wyoming County, West Virginia.

Regulation Affected: 30 CFR 75.507–1(a) (Electric equipment other than power-connection points; outby the last open crosscut return air; permissibility requirements).

Modification Request: The petitioner requests a modification of the existing standard to permit the use of battery-powered non-permissible surveying equipment outby the last open cross-cut in return airways, including, but not limited to, portable battery-operated mine transits, total station surveying equipment, distance meters, and laptop computers. The petitioner proposes to use up-to-date, practical, and accurate technology in the preparation of mine maps and ensure the safety of the miners by providing proper and accurate mining directional control in the mine. The petitioner states that:

(1) Application of the existing standard would result in a diminution of safety to the miners.

(2) Underground mining, by its nature, size, complexity, and relative closeness to other abandoned mines, gas/oil wells, and other features, requires that accurate and precise measurements be completed in a prompt and efficient manner.

(3) The use of currently available non-electronic equipment is less accurate and less dependable than the available electronic equipment and requires more exposure of surveyors to hazardous mining environments. As an alternative to compliance with the existing standard, the petitioner proposes the following:

(a) To examine all non-permissible electronic surveying equipment prior to use in or inby the last open crosscut to ensure that the equipment is being maintained in a safe operating condition, and have a qualified person, as defined in 30 CFR 75.153, examine the equipment at intervals not to exceed 7 days. The examination results will be recorded in the weekly examination of electrical equipment book. The examinations will include:

(i) Checks of the instrument for any physical damage and the integrity of the case.

(ii) Removal of the battery and an inspection for corrosion and damage.

(iii) Inspection of the contact points to ensure a secure connection to the battery.

(iv) Reinsertion of the battery and a power-up and shut-down of the instrument to ensure proper connections.

(v) Checks of the battery compartment cover to ensure that it is securely fastened.

(b) A qualified person, as defined in 30 CFR 75.151, will continuously monitor for methane immediately before and during the use of non-permissible surveying equipment in or inby the last open crosscut or in the return.

(c) Non-permissible surveying equipment will not be used if methane is detected in concentrations at or above 1.0 percent. When 1.0 percent or more of methane is detected while the non-permissible surveying equipment is being used, the equipment will be deenergized immediately and the non-permissible electronic equipment will be withdrawn out of the return.

(d) Non-permissible surveying equipment will not be used in areas where float coal dust is in suspension.

(e) Batteries contained in the surveying equipment will be changed out or charged in fresh air and not in the return.

(f) Qualified personnel who use the surveying equipment will be properly trained to recognize the hazards and limitations associated with the use of non-permissible surveying equipment.

(g) The non-permissible surveying equipment will not be put into service until MSHA has initially inspected the equipment and determined that it is in compliance with the terms and conditions in this petition.

(h) Within 60 days after the Proposed Decision and Order becomes final, the petitioner will submit proposed revisions for its approved 30 CFR Part 48 training plan to the District Manager. These proposed revisions will specify initial and refresher training regarding the terms and conditions stated in the Proposed Decision and Order.

The petitioner further states that the nature of work at times will require that surveying services that would be covered by this petition be provided on short notice and, therefore, does not want the petitions to apply to specific companies or mines. The petitioner states that the list of companies and mines in this petition is not all-inclusive.

The petitioner asserts that the proposed alternative method will at all times guarantee no less than the same measure of protection afforded by the existing standard.

Docket Number: M–2011–047–C.

Petitioner: Alpha Engineering Services, Inc., 216 Business Street, Beckley, West Virginia 25801.

Mines: Signature Mining, Coalburg No. 1 Mine, MSHA I.D. No. 46–09082, and Newtown Energy, Coalburg No. 1 Mine, MSHA I.D. No. 46–08993, and Patriot Coal, Harris No. 1 Mine, MSHA I.D. No. 46–01271, and Newtown Energy, Peerless Rachel Mine, MSHA I.D. No. 46–09258, located in Boone County, West Virginia; Arch-Wolf Run, Sentinel Mine, MSHA I.D. No. 46–04168, located in Barbour County, West Virginia; Arch-Wolf Run, Imperial Mine, MSHA I.D. No. 46–09115, and Arch-Wolf Run, Sago Mine, MSHA I.D. No. 46–08791, located in Upshur County, West Virginia; Arch-Wolf Run, Sycamore 2 Mine, MSHA I.D. No. 46–09060, located in Harrison County, West Virginia; Arch-Tygart Valley LLC, Tygart No. 1 Mine, MSHA I.D. No. 46–09192, located in Taylor County, West Virginia; Arch-Beckley LLC, Beckley Pocahontas Mine, MSHA I.D. No. 46–09216, and Performance Coal Co., Upper Big Branch Mine, MSHA I.D. No. 46–08436, located in Raleigh County, West Virginia; Newtown Energy, Eagle Mine, MSHA I.D. No. 46–08759, and Newtown Energy, Coalburg No. 2 Mine, MSHA I.D. No. 46–09231, and Speed Mining LLC, American Eagle Mine, MSHA I.D. No. 46–05437, located in Kanawha County, West Virginia; Prairie State, Lively Grove Mine, MSHA I.D. No. 11–03193, located in Washington County, Illinois; Pinnacle Mining, Pinnacle Mine, MSHA I.D. No. 46–01816, located in Wyoming County, West Virginia.

Regulation Affected: 30 CFR 77.1914(a) (Electrical equipment).

Modification Request: The petitioner requests a modification of the existing standard to permit the use of battery-powered non-permissible surveying equipment in shaft and slope construction, including, but not limited to, portable battery-operated mine transits, total station surveying equipment, distance meters, and laptop computers. The petitioner proposes to use up-to-date, practical, and accurate technology in the preparation of mine maps and ensure the safety of the miners by providing proper and accurate mining directional control in the mine. The petitioner states that:

(1) Application of the existing standard would result in a diminution of safety to the miners.

(2) Underground mining, by its nature, size, complexity, and relative closeness to other abandoned mines, gas/oil wells, and other features, requires that accurate and precise measurements be completed in a prompt and efficient manner.

(3) The use of currently available non-electronic equipment is less accurate and less dependable than the available electronic equipment and requires more exposure of surveyors to hazardous mining environments. As an alternative to compliance with the existing standard, the petitioner proposes the following:

(a) To examine all non-permissible electronic surveying equipment prior to use in or inby the last open crosscut to ensure the equipment is being maintained in a safe operating condition, and have a qualified person, as defined in 30 CFR 75.153, examine the equipment at intervals not to exceed 7 days. The examination results will be recorded in the weekly examination of electrical equipment book. The examinations will include:

(i) Checks of the instrument for any physical damage and the integrity of the case.

(ii) Removal of the battery and an inspection for corrosion and damage.

(iii) Inspection of the contact points to ensure a secure connection to the battery.

(iv) Reinsertion of the battery and a power-up and shut-down of the instrument to ensure proper connections.

(v) Checks of the battery compartment cover to ensure that it is securely fastened.

(b) A qualified person, as defined in 30 CFR 75.151, will continuously monitor for methane immediately before and during the use of non-permissible surveying equipment in or inby the last open crosscut or in the return.

(c) Non-permissible surveying equipment will not be used if methane is detected in concentrations at or above 1.0 percent. When 1.0 percent or more of methane is detected while the non-permissible surveying equipment is being used, the equipment will be deenergized immediately and the non-permissible electronic equipment will be withdrawn out of the return.

(d) Non-permissible surveying equipment will not be used in areas where float coal dust is in suspension.

(e) Batteries contained in the surveying equipment will be changed out or charged in fresh air and not in the return.

(f) Qualified personnel who use the surveying equipment will be properly trained to recognize the hazards and limitations associated with the use of non-permissible surveying equipment.

(g) The non-permissible surveying equipment will not be put into service until MSHA has initially inspected the equipment and determined that it is in compliance with the terms and conditions in this petition.

(h) Within 60 days after the Proposed Decision and Order becomes final, the petitioner will submit proposed revisions for its approved 30 CFR Part 48 training plan to the District Manager. These proposed revisions will specify initial and refresher training regarding the terms and conditions stated in the Proposed Decision and Order.

The petitioner further states that the nature of work at times will require that surveying services that would be covered by this petition be provided on short notice and, therefore, does not want the petitions to apply to specific companies or mines. The petitioner states that the list of companies and mines in this petition is not all-inclusive.

The petitioner asserts that the proposed alternative method will at all times guarantee no less than the same measure of protection afforded by the existing standard.

Docket Number: M–2011–014–M.

Petitioner: St. Marys Cement, Inc. (U.S.), 16000 Bells Ray Road, P.O. Box 367, Charlevoix, Michigan 49720.

Mine: St. Marys Cement, Charlevoix Plant, MSHA I.D. No. 20–00038, 16000 Bells Ray Road, P.O. Box 367, Charlevoix, Michigan 49720.

Regulation Affected: 30 CFR 56.14101(a)(2) and (3) (Brakes).

Modification Request: The petitioner requests a modification of the existing standard for self-propelled mobile equipment for its 1997 Tennant Sweeper, Model #830. The petitioner states that:

(1) The Tennant Sweeper is operated only on paved flat roads within the surface mine property.

(2) The sweeper primarily operates with use of a hydraulic system. When the foot is taken off the accelerator the sweeper stops.

(3) The back brakes are currently inoperable and the unit is so old that the parts are hard to obtain to fix the system.

(4) The sweeper has a functional front braking system capable of stopping and holding the vehicle with a full load on the steepest incline it travels.

(5) The sweeper is operated only on day shift, only travels on dry roads and dusty days when the roads are not wet or slippery, and is put up for the winter.

(6) The sweeper is not capable of traveling over 5 miles per hour. It is generally run between 3 and 5 miles per hour within the plant. The standard on brakes requires at least 10 miles per hour to test the brakes, and the sweeper cannot go that fast.

(7) The sweeper has a fully functional parking brake system capable of holding the machine with a full load on the steepest incline it travels.

(8) The unit is not being supported by Tennant, the manufacturer.

(9) Any spare parts that can be obtained will no longer be produced once they are used up.

(10) What is available to fix the unit has been ordered, and the unit is needed to comply with environmental regulations.

As an alternative, the petitioner proposes to rely on the hydraulic system, the front brake system, and the parking brake to stop and hold the equipment with its typical load on the maximum grade it travels.

The petitioner asserts that the proposed alternative method will at all times guarantee the miners no less than the same measure of protection as provided by the existing standard.

Dated: February 10, 2012.

Patricia W. Silvey,

Certifying Officer.

[FR Doc. 2012–3614 Filed 2–15–12; 8:45 am]

BILLING CODE 4510–43–P

NATIONAL SCIENCE FOUNDATION

Agency Information Collection Activities: Comment Request

AGENCY: National Science Foundation.

ACTION: Submission for OMB Review; Comment Request.

SUMMARY: The National Science Foundation (NSF) has submitted the following information collection requirement to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. This is the second notice for public comment; the first was published in the **Federal Register** at 76 FR 77854. NSF is forwarding the proposed renewal submission to the Office of Management and Budget (OMB) for clearance simultaneously with the publication of this second notice. The full submission may be found at: *http://www.reginfo.gov/public/do/PRAMain.*

Comments: Comments regarding (a) whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility and clarity of the information to be collected; or (d) ways to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology should be addressed to: Office of Information and Regulatory Affairs of OMB, Attention: Desk Officer for National Science Foundation, 725 17th Street NW., Room 10235, Washington, DC 20503, and to Suzanne H. Plimpton, Reports Clearance Officer, National Science Foundation, 4201 Wilson Boulevard, Suite 295, Arlington, Virginia 22230 or send email to *splimpto@nsf.gov.* Comments regarding these information collections are best assured of having their full effect if received within 30 days of this notification. Copies of the submission(s) may be obtained by calling 703–292–7556.

FOR FURTHER INFORMATION CONTACT: Suzanne H. Plimpton at (703) 292–7556 or send email to *splimpto@nsf.gov.* Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339, which is accessible 24 hours a day, 7 days a week, 365 days a year (including federal holidays).

NSF may not conduct or sponsor a collection of information unless the collection of information displays a currently valid OMB control number and the agency informs potential persons who are to respond to the collection of information that such persons are not required to respond to the collection of information unless it displays a currently valid OMB control number.

SUPPLEMENTARY INFORMATION:

Title of Collection: Grantee Reporting Requirements for the Engineering Research Centers (ERCs).

OMB Number: 3145–New.

Type of Request: Intent to seek approval to establish an information collection.

Abstract:

Proposed Project: The Engineering Research Centers (ERC) program supports an integrated, interdisciplinary research environment to advance fundamental engineering knowledge and engineered systems; educate a globally competitive and diverse engineering workforce from K–12 on; and join academe and industry in partnership to achieve these goals. ERCs conduct world-class research through partnerships of academic institutions, national laboratories, industrial organizations, and/or other public/private entities. New knowledge thus created is meaningfully linked to society.

ERCs conduct world-class research with an engineered systems perspective that integrates materials, devices, processes, components, control algorithms and/or other enabling elements to perform a well-defined function. These systems provide a unique academic research and education experience that involves integrative complexity and technological realization. The complexity of the systems perspective includes the factors associated with its use in industry, society/environment, or the human body.

ERCs enable and foster excellent education, integrate research and education, speed knowledge/technology transfer through partnerships between academe and industry, and prepare a more competitive future workforce. ERCs capitalize on diversity through participation in center activities and demonstrate leadership in the involvement of groups underrepresented in science and engineering.

Centers will be required to submit annual reports on progress and plans, which will be used as a basis for performance review and determining the level of continued funding. To support this review and the management of a Center, ERCs will also be required to submit management and performance indicators annually to NSF via a data collection Web site that is managed by a technical assistance contractor. These indicators are both quantitative and descriptive and may include, for example, the characteristics of center personnel and students; sources of cash and in-kind support; expenditures by operational component; characteristics of industrial and/or other sector participation; research activities; education activities; knowledge transfer activities; patents, licenses; publications; degrees granted to students involved in Center activities; descriptions of significant advances and other outcomes of the ERC effort. Such reporting requirements will be included in the cooperative agreement which is binding between the academic institution and the NSF.

Each Center's annual report will address the following categories of activities: (1) Vision and impact, (2) strategic plan, (3) research program, (4) innovation ecosystem and industrial collaboration, (5) education, (6) infrastructure (leadership, management, facilities, diversity) and (7) budget issues.

For each of the categories the report will describe overall objectives for the year, progress toward center goals, problems the Center has encountered in making progress towards goals and how they were overcome, plans for the future and anticipated research and other barriers to overcome in the following year, and specific outputs and outcomes.

Use of the Information: The data collected will be used for NSF internal reports, historical data, performance review by peer site visit teams, program level studies and evaluations, and for securing future funding for continued ERC program maintenance and growth.

Estimate of Burden: 100 hours per center for 17 centers for a total of 1700 hours.

Respondents: Academic institutions.

Estimated Number of Responses per Report: One from each of the 17 ERCs.

Dated: February 10, 2012.

Suzanne H. Plimpton,

Reports Clearance Officer, National Science Foundation.

[FR Doc. 2012–3605 Filed 2–15–12; 8:45 am]

BILLING CODE 7555–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2012–0037]

WORKSHOP Sponsored by the Nuclear Regulatory Commission and the Electric Power Research Institute on the Treatment of Probabilistic Risk Assessment Uncertainties: Public Meeting

AGENCY: U.S. Nuclear Regulatory Commission.

ACTION: Notice of public meeting.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Regulatory Research (RES), in cooperation with the Electric Power Research Institute (EPRI), will hold a joint workshop on the Treatment of Probabilistic Risk Assessment (PRA) Uncertainties. Since 2002, RES and EPRI, under a Memorandum of Understanding (MOU) on Cooperative Nuclear Safety Research, have been developing state-of-the-art methods for conduct of PRA.

The purpose of the workshop is to bring together experts to gain a better understanding of the sources of uncertainty, how they manifest in the PRA, and their potential significance to the PRA model and results. More specifically, the workshop will address uncertainties associated with risk assessments for internal fires, seismic events, low power and shutdown (LPSD) conditions, and for the Level 2 portion of PRAs.

DATES: Wednesday, February 29, 2012 (8:30 a.m.–5 p.m.);

Thursday, March 1, 2012 (8:30 a.m.—12:30 p.m.)

ADDRESSES: The Legacy Hotel & Meeting Centre; 1775 Rockville Pike; Rockville, Maryland 20852.

Meeting Agenda: The agenda for this meeting can be accessed at *http://www.nrc.gov/public-involve/public-meetings/index.cfm.*

Because of limited available space, attendees are asked to pre-register (there is not a registration fee) as soon as possible. There will be the ability to call-in to the workshop. Please contact Matt Dennis, Sandia National Laboratories, at 505–284–0781, email: *mldenni@sandia.gov* to register and to obtain the call-in phone line number.

FOR FURTHER INFORMATION CONTACT: Mary T. Drouin, Sr. Program Manager, Performance and Reliability Branch, Division of Risk Analysis, Office of Nuclear Regulatory Research, United States Nuclear Regulatory Commission, Tel: 301–251–7574, Email: *Mary.Drouin@nrc.gov.*

Conduct of the Meeting

This meeting is a Category 3 meeting.* The public is invited to participate in this meeting by providing comments and asking questions throughout the meeting. Please note this workshop is being conducted in a classroom format; registration is required to ensure space availability.

The NRC provides reasonable accommodation to individuals with disabilities where appropriate. If you need a reasonable accommodation to participate in this workshop, or need the workshop notice or agenda in another format (e.g., Braille, large print), please notify the NRC is meeting contact. Determinations on requests for reasonable accommodation will be made on a case-by-case basis.

Dated at Rockville, Maryland, this 8th day of February, 2012.

For the Nuclear Regulatory Commission.

Kevin A. Coyne,

Branch Chief, Probability Probabilistic Risk Assessment Branch, Division of Risk Analysis, Office of Nuclear Regulatory Research.

[FR Doc. 2012–3677 Filed 2–15–12; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2010–0355]

USEC Inc. (American Centrifuge Lead Cascade Facility and American Centrifuge Plant); Direct Transfer of Licenses

In the Matter of USEC INC. (American Centrifuge Lead Cascade Facility and American Centrifuge Plant); Order EA–12–

* Meetings between the NRC technical staff and external stakeholders are open for interested members of the public, petitioners, interveners, or other parties to attend as observers pursuant to Commission policy statement, ''Enhancing Public Participation in NRC Meetings,'' (67 FR 36920; May 28, 2002).

027, Docket Nos. 70–7003, 70–7004, License Nos. SNM–7003, SNM–2011

Order Extending the Date by Which the Direct Transfer of Licenses Is To Be Completed

I

USEC Inc., (USEC) is the holder of materials licenses SNM–7003 and SNM–2011 for the American Centrifuge Lead Cascade Facility (Lead Cascade) and American Centrifuge Plant (ACP), respectively, which authorize the licensee to: (1) Possess and use source and special nuclear material at the Lead Cascade at the former Portsmouth Gaseous Diffusion Plant site in Piketon, Ohio, in accordance with materials license number SNM–7003; and (2) construct and operate a gas centrifuge uranium enrichment facility (the ACP) at the former Portsmouth Gaseous Diffusion Plant site in Piketon, Ohio, in accordance with materials license number SNM–2011.

II

The U.S. Nuclear Regulatory Commission's (NRC) Order EA–11–013, dated February 10, 2011, approved the direct transfer of the licenses of the above facilities from USEC to the limited liability company American Centrifuge Operating, LLC (ACO), pursuant to Sections 161(b), 161(i), 161(o) and 184 of the Atomic Energy Act, as amended; 42 United States Code (U.S.C.) 2201(b), 2201(i), and 2234; and Title 10 of the *Code of Federal Regulations* (10 CFR) 30.34(b), 10 CFR 40.46, ''Inalienability of Licenses,'' and 10 CFR 70.36, ''Inalienability of Licenses.'' By Order EA–11–180, dated August 8, 2011, the NRC approved an extension to Order EA–11–013 until February 9, 2012. By their terms, both orders will become null and void if the license transfers are not completed by February 9, 2012. However, both the February 10, 2011, and the August 9, 2011, Orders further state that upon written application and for good cause shown, the implementation period for the license transfers may be extended by further Order.

III

By letter dated January 6, 2012, and supplemented by letter dated January 27, 2012, USEC submitted a request to extend the date by which the license transfers must be completed from February 9, 2012, to February 8, 2013. USEC stated that Condition 3 of Order EA–11–013 will be satisfied following completion of actions with the DOE, without any linkage to the loan guarantee. In its January 27, 2012, letter, USEC stated that due to uncertainty, it appears that the date for completion of activities associated with the sub-lease will extend beyond May 18, 2012. Accordingly, USEC stated that it will not be able to fully implement the conditions in Order EA–11–013 by February 9, 2012, and is requesting a second extension to Order EA–11–013.

USEC states that there have been no changes in the information and technical and financial qualifications presented in its September 10, 2010, request to transfer the licenses (Agencywide Documents Access and Management System (ADAMS) Accession No. ML102660371). The NRC staff notes that its basis for approving the transfers of USEC's licenses for the Lead Cascade and the ACP from USEC to ACO is documented in its safety evaluation report (SER, ADAMS Accession No. ML103630748) supporting the February 10, 2011, Order.

The NRC staff reviewed the information provided by USEC in its September 10, 2010, transfer of licenses request, the information provided in its July 22, 2011, first extension request (ADAMS Accession No. ML11210B497), and supplemental electronic communication dated August 1, 2011 (ADAMS Accession No. ML11213A282), and the information provided in its January 6, 2012, second extension request, and supplemental letter dated January 27, 2012. Based on this review of the information provided by USEC, the NRC staff concludes that the basis for originally approving the transfers of USEC's licenses for the Lead Cascade and the ACP from USEC to ACO remains valid. The NRC staff evaluated the January 6, 2012, submittal and the January 27, 2012, supplemental letter and determined that USEC has shown good cause to extend the implementation period of Order EA–11–013 a second time and, therefore, the implementation date for Order EA–11–013 should be extended to February 8, 2013, the date by which the transfer of licenses must be completed.

IV

Accordingly, pursuant to Sections 161b, 161i, 161o, and 184 of the Atomic Energy Act of 1954, as amended, 42 U.S.C. 2201(b), 2201(i), and 2234; and 10 CFR 30.34(b), 10 CFR 40.46, ''Inalienability of Licenses,'' and 10 CFR 70.36, ''Inalienability of Licenses,'' *It Is Hereby Ordered* that the date by which the license transfers described above must be completed is extended to February 8, 2013. If the proposed direct transfer of licenses is not completed by February 8, 2013, this Order and the February 10, 2011, Order shall become null and void. However, upon written application and for good cause shown, the February 8, 2013, date may be extended by further Order.

This Order is effective upon issuance. The Order of February 10, 2011, as modified by the August 8, 2011, Order and this Order, remains in full force and effect.

For further details with respect to this Order, see the submittal dated January 6, 2012 (ADAMS Accession No. ML11210B497), the supplemental letter dated January 27, 2012 (ADAMS Accession No. ML12032A279), and the SER documenting NRC's staff evaluation of USEC's submittal dated February 8, 2012 (ADAMS Accession No. ML12027A034), which may be examined—and/or copied for a fee—at the NRC's Public Document Room, located at One White Flint North, 11555 Rockville Pike (First Floor), Rockville, MD 20852; and accessible online in the NRC Library at *http://www.nrc.gov/reading-rm/adams.html.*

Dated at Rockville, Maryland, this 8th day of February 2012.

For the U.S. Nuclear Regulatory Commission.

Catherine Haney,

Director, Office of Nuclear Material Safety and Safeguards.

[FR Doc. 2012–3675 Filed 2–15–12; 8:45 am]

BILLING CODE 7590–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66375; File No. SR–CBOE–2011–117]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Order Approving Proposed Rule Change Relating to Its Automated Improvement Mechanism

February 10, 2012.

On December 14, 2011, the Chicago Board Options Exchange, Incorporated (''Exchange'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] a proposed rule change to amend CBOE Rule 6.74A, which relates to the Exchange's Automated Improvement Mechanism (''AIM''). The proposal would permit a Trading Permit Holder (''TPH''), when submitting an agency order to AIM to initiate an

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

auction, to elect to have last priority in the AIM auction's order allocation.[3]

The proposed rule change was published for comment in the **Federal Register** on December 29, 2011.[4] The Commission received no comments on the proposal.

After careful review, the Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder applicable to a national securities exchange [5] and, in particular, the requirements of Section 6(b)(5) of the Act,[6] in that it is designed to provide additional flexibility for TPHs to obtain executions on behalf of their customers through AIM because the initiating TPH may elect to have last priority. The Commission believes that, as a result of this flexibility, there may be increased usage of AIM auctions and the mechanism may attract new participants, thereby helping to further competition and to enhance the possibility of price improvement on behalf of customers.[7]

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[8] that the proposed rule change (SR–CBOE–2011–117) be, and it hereby is, approved.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[9]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3607 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

[3] In an AIM auction, described here generally, a TPH submits into the mechanism an order that it represents as agent (''Agency Order'') along with a contra-side order at a specified price (which must comply with parameters set forth in Rule 6.74A) and for the same size that either represents principal interest of the TPH or is a solicited order. Certain Exchange participants, as set forth in Rule 6.74A, then can compete with the contra-side order by submitting bids (offers) to execute against the Agency Order. After better-priced orders are filled and public customers competing at the best price receive their allocations, the TPH is granted priority ahead of other participants to execute against 40% (in some circumstances 50%) of the original size of the Agency Order. Under the proposed rule change, the initiating TPH will be able to elect to have last priority.

[4] *See* Securities Exchange Act Release No. 66038 (December 22, 2011), 76 FR 82016.

[5] In approving this proposed rule change, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[6] 15 U.S.C. 78f(b)(5).

[7] The Commission notes that Chapter V, Section 18(f)(v) of the Rules of the Boston Exchange Group, LLC, ''The Price Improvement Period'' (''PIP''), includes a similar provision that permits an options participant initiating a PIP auction to designate a lower amount than the 40% to which it is otherwise entitled upon the conclusion of the PIP auction.

[8] 15 U.S.C. 78s(b)(2).

[9] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66382; File No. SR–CBOE–2012–014]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change To Establish Transaction Fees for Options on the CBOE Emerging Markets ETF Volatility Index, the CBOE Brazil ETF Volatility Index and CBOE Oil ETF Volatility Index

February 10, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act'') [1] and Rule 19b–4 thereunder,[2] notice is hereby given that on February 1, 2012, the Chicago Board Options Exchange, Incorporated (the ''Exchange'' or ''CBOE'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

CBOE proposes to amend its Fees Schedule to establish fees for transactions in options on the CBOE Emerging Market ETF Volatility Index (''VXEEM''), the CBOE Brazil ETF Volatility Index (''VXEWZ'') and the CBOE Crude Oil ETF Volatility Index (''OVX''). The text of the proposed rule change is available on the Exchange's Web site (*http://www.cboe.org/legal*), at the Exchange's Office of the Secretary, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange received approval to list and trade options on the CBOE Emerging Market ETF Volatility Index (''VXEEM''), the CBOE Brazil ETF Volatility Index (''VXEWZ'') and the CBOE Crude Oil ETF Volatility Index (''OVX'') (collectively herein, ''volatility indexes''), which are up-to-the-minute market estimates of the expected volatility of their corresponding exchange-traded funds (''ETF'') [3] calculated by using real-time bid/ask quotes of CBOE listed options on the respective ETF.[4] The volatility indexes use nearby and second nearby options with at least 8 days left to expiration and then weights them to yield a constant, 30-day measure of the expected (implied) volatility. The Exchange will list VXEEM options beginning on January 30, 2012, VXEWZ options beginning on February 20, 2012 and OVX options beginning on March 6, 2012.

The purpose of this rule change is to clarify that the existing transaction fees for ''Volatility Indexes'' shall apply for transactions in VXEEM options, VXEWZ options and OVX options except that the existing Surcharge Fee (currently $.10 per contract for Volatility Index options) will not apply to VXEEM options, VXEWZ options and OVX options.[5] In addition, the Exchange's marketing fee [6] shall not apply to VXEEM options, VXEWZ options and OVX options. The Product Research & Development fee shall apply to VXEEM options, VXEWZ options and OVX options at the rate of $0.10 per contract.[7]

For reference, the existing Volatility Index transactions fees that will apply

[3] The corresponding ETFs are: the iShares MSCI Emerging Markets Index ETF (''EEM''), the iShares MSCI Brazil Index ETF (''EWZ'') and the United States Oil Fund (''USO'') .

[4] *See* Securities Exchange Act Release No. 64551 (May 26, 2011), 76 FR 32000 (June 2, 2011) (approving SR–CBOE–2011–026).

[5] This fee is assessed to help the Exchange recoup license fees the Exchange pays to the different index licensors in order to list options on the respective indexes.

[6] *See* Footnote 6 of the Fees Schedule.

[7] *See* Section 1 (Index Options), VII.(B) to the Fees Schedule. The Product Research & Development fee is assessed to help offset some of the costs and expenses expended for product research and development and ongoing maintenance of CBOE's products. The Product Research & Development fee applies to all non-public customer transactions (*i.e.,* CBOE and non-Trading Permit Holder market-maker, Clearing Trading Permit Holder and broker-dealer), including voluntary professionals and professionals. *See* Footnote 12 of the Fees Schedule.

to VXEEM options, VXEWZ options and OVX options are as follows:

- $0.40 per contract for customer transactions;
- $0.40 per contract for voluntary professional transactions;
- $0.40 per contract for professional transactions
- $0.20 per contract for CBOE Market-Maker/DPM transactions;
- $0.25 per contract for Clearing Trading Permit Holder proprietary transactions; [8]
- $0.40 per contract for broker-dealer transactions;
- $0.10 per contract CFLEX Surcharge Fee;

$0.03 per contract floor brokerage fee; [9]

- $0.015 per contract floor brokerage fee for crossed orders; [10]
- $0.03 per contract par official fee; [11] and
- $0.015 per contract for par official fee for crossed orders.[12]

2. *Statutory Basis*

The Exchange believes the proposed rule change is consistent with Section 6(b) of the Act,[13] in general, and furthers the objectives of Section 6(b)(4) [14] of the Act in particular, in that it is designed to provide for the equitable allocation of reasonable dues, fees, and other charges among CBOE Trading Permit Holders and other persons using its facilities.

The Exchange is excluding VXEEM, VXEWZ and OVX options from the Index License/Surcharge Fee of $0.10 per contract because that fee is assessed to help the Exchange recoup license fees that the Exchange pays to different index licensors in order to list options on the respective indexes. The Exchange does not pay fees to index licensors to list VXEEM, VXEWZ and OVX options. The Exchange is assessing a Product Research & Development/Surcharge fee to all non-public customer transactions (*i.e.,* CBOE and non-Trading Permit Holder market maker, Clearing Trading Permit Holder and broker-dealer), including voluntary professionals and professionals. The Product Research & Development/Surcharge fee is assessed to help the Exchange offset some of the costs and expenses expended for product research and development and ongoing maintenance associated with these new volatility index products.

The Exchange believes that the fees are reasonable because they are comparable to fees that the Exchange currently assesses for another similar volatility index option, *i.e.,* CBOE Gold ETF Volatility Index (''GVZ'') options. The Exchange believes the level of the fees furthers the Exchange's goal of introducing new products to the marketplace that are competitively priced.

The Exchange believes that the fees are equitable and do not unfairly discriminate because they provide comparable pricing among similar categories of market participants. The Exchange believes that a fee of $0.20 per contract for CBOE Market-Maker/DPM transactions is equitable since those market participants provide a valuable market service by adding liquidity to the Exchange and since they are subject to liquidity provider obligations. This standard rate is not subject to the Liquidity Provider Sliding Scale as set forth in Footnote 10 to the Fees Schedule. The Exchange also believes that a fee of $0.25 per contract for Clearing Trading Permit Holders is equitable since they contribute capital to facilitate customer orders, which in turn provides a deeper pool of liquidity that benefits all market participants.

B. Self-Regulatory Organization's Statement on Burden on Competition

CBOE does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The proposed rule change is designated by the Exchange as establishing or changing a due, fee, or other charge, thereby qualifying for effectiveness on filing pursuant to Section 19(b)(3)(A) of the Act [15] and subparagraph (f)(2) of Rule 19b–4 [16] thereunder.

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–CBOE–2012–014 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–CBOE–2012–014. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro/shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing will also be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File No. SR–CBOE–

[8] This is the standard rate that is subject to the CBOE Proprietary Products Sliding Scale for Clearing Trading Permit Holder Proprietary Orders as set forth in Footnote 11 to the Fees Schedule.

[9] *See* Section 3 (Floor Brokerage and Par Official Fees) to the Fees Schedule and Footnotes 1, 5 and 15 of the Fees Schedule.

[10] *Id.*

[11] *Id.*

[12] *Id.*

[13] 15 U.S.C. 78f(b).

[14] 15 U.S.C. 78f(b)(4).

[15] 15 U.S.C. 78s(b)(3)(A).

[16] 17 CFR 240.19b–4(f)(2).

2012–014 and should be submitted on or before March 8, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[17]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3641 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66379; File No. SR–NYSEArca–2012–11]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Amending the NYSE Arca Equities Fee Schedule Increasing the Indication of Interest Tier 1 Credit and the Tracking Order Tier 1 Credit for ETP Holders and Market Makers

February 10, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1] and Rule 19b–4 thereunder,[2] notice is hereby given that, on February 1, 2012, NYSE Arca, Inc. (the ''Exchange'' or ''NYSE Arca'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend the NYSE Arca Equities Fee Schedule (''Fee Schedule'') to increase the indication of interest (''IOI'') Tier 1 credit and the Tracking Order Tier 1 credit for ETP Holders and Market Makers. The text of the proposed rule change is available at the Exchange, the Commission's Public Reference Room, and *www.nyse.com.*

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend the Fee Schedule to increase the IOI Tier 1 credit [3] and the Tracking Order [4] Tier 1 credit for ETP Holders and Market Makers. The credits are designed to attract trading interest to and promote liquidity on the Exchange. The Exchange does not propose to make any changes to the other IOI or Tracking Order Tiers.

IOI Tier 1 Credit

Currently, an IOI Tier 1 credit is offered to each ETP Holder and Market Maker that send IOIs to the Exchange resulting in executions with an average daily share volume (''ADV'') per month greater than or equal to 10 million shares in Tape A, B, and C securities. The credit is $0.0012 per share for each share up to and including 15 million shares and $0.0015 per share for each share in excess of 15 million shares.[5]

The Exchange proposes to amend the IOI Tier 1 credit so that each ETP Holder and Market Maker will receive a credit of $0.0015 per share for all shares if its IOIs result in executions on the Exchange with an ADV per month greater than 15 million shares. The Exchange will continue to provide a $0.0012 credit per share for IOIs sent to the Exchange resulting in executions with an ADV per month up to and including 15 million shares (assuming the 10 million share threshold is met).

For example, under the current Fee Schedule, if an ETP Holder sends IOIs to the Exchange resulting in executions with an ADV per month of 17 million shares, the ETP Holder receives a $0.0012 per share credit for the first 15 million shares and a $0.0015 per share credit for the 2 million shares in excess of the 15 million shares. Under the proposed Fee Schedule, the ETP Holder will receive a $0.0015 per share credit for all 17 million shares.

Tracking Order Tier 1

Currently, the Tracking Order Tier 1 credit is offered to each ETP Holder and Market Maker that sends Tracking Orders to the Exchange resulting in executions with an ADV per month greater than or equal to 5 million shares in Tape A, B, and C securities.[6] The credit is $0.0012 per share for each share up to and including 15 million shares and $0.0015 per share for each share in excess of 15 million shares.

The Exchange proposes to amend the Tracking Order Tier 1 credit so that each ETP Holder and Market Maker will receive a credit of $0.0015 per share for all shares if its Tracking Orders result in executions on the Exchange with an ADV per month greater than 15 million shares. The Exchange will continue to credit ETP Holders $0.0012 per share for Tracking Orders that result in executions up to and including 15 million shares (assuming the 5 million share threshold is met).

For example, under the current Fee Schedule, if an ETP Holder sends Tracking Orders to the Exchange resulting in executions with an ADV per month of 17 million shares, the ETP Holder receives a $0.0012 per share credit for the first 15 million shares and a $0.0015 per share credit for the remaining 2 million shares. Under the proposed Fee Schedule, the ETP Holder will receive a $0.0015 per share credit for all 17 million shares.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with Section 6(b) of the Securities Exchange Act of 1934 (the ''Act''),[7] in general, and Section 6(b)(4) of the Act,[8] in particular, in that it is designed to provide for the equitable allocation of reasonable dues, fees, and other charges among its members and other persons using its facilities. The proposed change is

[17] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] An IOI is a non-displayed indication of symbol, size and side, which does not interact with the NYSE Arca Book. At their discretion, participating ETP Holders and Market Makers may send an IOI to the Exchange, which in turn will consider the IOI when determining potential destinations for outbound routes. *See* Securities Exchange Act Release No. 58397 (August 20, 2008), 73 FR 50389 (August 26, 2008) (SR–NYSEArca–2008–83).

[4] A Tracking Order is an undisplayed, priced round lot order that is eligible for execution in the Tracking Order Process against orders equal to or less than the aggregate size of Tracking Order interest available at that price. See NYSE Arca Equities Rule 7.31(f).

[5] *See* Securities Exchange Act Release No. 60495 (August 13, 2009), 74 FR 41957 (August 19, 2009) (SR–NYSEArca–2009–72). The Exchange proposed an incremental credit in an effort to attract and enhance participation in the IOI program, by offering attractive rebates and volume based incentives.

[6] *See* Securities Exchange Act Release No. 60944 (November 5, 2009), 74 FR 58668 (November 13, 2009) (SR–NYSEArca–2009–99). The Exchange proposed to add new transaction credits stemming from the use of Tracking Orders in an effort to enhance participation on the Exchange and to offer increased liquidity to ETP Holders and Market Makers.

[7] 15 U.S.C. 78f(b).

[8] 15 U.S.C. 78f(b)(4).

equitably allocated and not unfairly discriminatory because it applies uniformly to all similarly situated ETP Holders and Market Makers that send IOIs and Tracking Orders to the Exchange. The Exchange believes that the proposal also is reasonable and equitably allocated because it provides higher credits to ETP Holders and Market Makers that contribute to market quality by providing higher volumes of liquidity, and it is consistent with other tiered credits on the Exchange that pay a rebate on all volume and not just the incremental volume. The Exchange believes that increasing the credits will attract additional order flow and liquidity to the Exchange.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change is effective upon filing pursuant to Section 19(b)(3)(A)[9] of the Act and subparagraph (f)(2) of Rule 19b–4[10] thereunder, because it establishes a due, fee, or other charge imposed by the NYSE Arca.

At any time within 60 days of the filing of such proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–NYSEArca-2012–11 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEArca-2012–11. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10:00 a.m. and 3:00 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEArca-2012–11 and should be submitted on or before March 8, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[11]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3672 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

[9] 15 U.S.C. 78s(b)(3)(A).

[10] 17 CFR 240.19b–4(f)(2).

[11] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66378; File No. SR–NYSEArca–2012–13]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Amending the NYSE Arca Equities Fee Schedule To Increase the Investor Tier 1 Credit for ETP Holders and Market Makers

February 10, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] notice is hereby given that, on February 1, 2012, NYSE Arca, Inc. (the ''Exchange'' or ''NYSE Arca'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend the NYSE Arca Equities Fee Schedule (''Fee Schedule'') to increase the Investor Tier 1 credit for ETP Holders and Market Makers. The text of the proposed rule change is available at the Exchange, the Commission's Public Reference Room, and *www.nyse.com.*

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend the Fee Schedule to increase the Investor

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

Tier 1 credit for ETP Holders and Market Makers. The credit is designed to attract trading interest to and promote liquidity on the Exchange. The Exchange does not propose to make any changes to the Investor Tier 2 credit.

Currently, the Investor Tier 1 allows customers to earn a credit of $0.0032 per share for executed orders that provide liquidity to the Book for Tape A, Tape B and Tape C securities when they meet all of the following criteria on a monthly basis:

- Maintain a ratio of cancelled orders to total orders of less than 30%. In calculating this ratio, the Exchange will exclude Immediate-or-Cancel orders, which are liquidity removing in nature.
- Maintain a ratio of executed liquidity adding volume to total volume of greater than 80%.
- Firms must add liquidity that represents 0.45% or more of the total US average daily consolidated share volume (''ADV'') per month (volume on days when the market closes early is excluded from the calculation of ADV).[3]

For example, if US ADV is 8.5 billion shares in a given month, the minimum adding ADV requirement for Investor Tier 1 would be 38.25 million adding shares a day.

The Exchange proposes to amend the Investor Tier 1 credit so that each ETP Holder and Market Maker will receive a credit of $0.0033 per share for orders that provide liquidity to the Book when they meet the above criteria on a monthly basis.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with Section 6(b) of the Securities Exchange Act of 1934 (the ''Act''),[4] in general, and Section 6(b)(4) of the Act,[5] in particular, in that it is designed to provide for the equitable allocation of reasonable dues, fees, and other charges among its members and other persons using its facilities. The proposed change is equitably allocated and not unfairly discriminatory because it applies uniformly to all similarly situated ETP Holders and Market Makers that provide liquidity to the Exchange. The Exchange believes that the proposal also is reasonable and equitably allocated because it provides higher credits to ETP Holders and Market Makers that contribute to market quality by providing higher volumes of liquidity. The Exchange believes that increasing the credits will attract additional order flow and liquidity to the Exchange.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change is effective upon filing pursuant to Section 19(b)(3)(A)[6] of the Act and subparagraph (f)(2) of Rule 19b–4[7] thereunder, because it establishes a due, fee, or other charge imposed by the NYSE Arca.

At any time within 60 days of the filing of such proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–NYSEArca–2012–13 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEArca–2012–13. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEArca–2012–13 and should be submitted on or before March 8, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[8]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3671 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66380; File No. SR–BATS–2012–009]

Self-Regulatory Organizations; BATS Exchange, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change To Modify Exchange Rule 11.23 Relating to Auctions of Exchange-Listed Securities

February 10, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b-4 thereunder,[2]

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[3] *See* Securities Exchange Act Release No. 66115 (January 6, 2012), 77 FR 1969 (January 12, 2012) (SR–NYSEArca–2011–101) (notice of filing and immediate effectiveness of a proposed rule change replacing numerical thresholds with percentage thresholds for the Investor Tiers' volume requirements).

[4] 15 U.S.C. 78f(b).

[5] 15 U.S.C. 78f(b)(4).

[6] 15 U.S.C. 78s(b)(3)(A).

[7] 17 CFR 240.19b–4(f)(2).

[8] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

notice is hereby given that on February 3, 2012, BATS Exchange, Inc. (the ''Exchange'' or ''BATS'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange is filing with the Commission a proposal to amend Rule 11.23 entitled ''Auctions'' to allow orders designated to participate in the opening auction on the Exchange (''Opening Auction'') to participate in an auction in the initial public offering (''IPO'') for a security on the Exchange (''IPO Auction'').

The text of the proposed rule change is available at the Exchange's Web site at *http://www.batstrading.com*, at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in Sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange recently proposed and received approval of rules governing auctions conducted on the Exchange for securities listed on the Exchange (''Exchange Auctions'').[3] Specifically, the Exchange adopted rules for conducting an Opening Auction, a closing auction on the Exchange, an IPO Auction, or an auction in the event of a halt of trading in the security. The purpose of this filing is to allow orders designated to participate in the Opening Auction to also participate in an IPO Auction, as governed by Rule 11.23.

Specifically, the Exchange proposes to amend several portions of Rule 11.23 to allow MOO, LOO, and LLOO orders to participate in IPO Auctions. Under the proposal, MOO orders would behave like market orders participating in an IPO Auction currently behave. LOO and LLOO orders would behave like limit orders participating in an IPO Auction currently behave. In order to effect the change, the Exchange proposes to amend the definition of Eligible Auction Orders for IPO Auctions to include those orders designated to exclusively participate in the Opening Auction. The Exchange also proposes modifications to the definitions of MOO, LOO, and LLOO orders and to make clear that these Opening Auction orders that are not executed as part of the IPO Auction would be cancelled immediately following the IPO Auction, exactly as currently occurs in the Opening Auction.

2. Statutory Basis

The Exchange believes that its proposal is consistent with the requirements of the Act and the rules and regulations thereunder that are applicable to a national securities exchange, and, in particular, with the requirements of Section 6(b) of the Act.[4] In particular, the proposal is consistent with Section 6(b)(5) of the Act,[5] because it would promote just and equitable principles of trade, remove impediments to, and perfect the mechanism of, a free and open market and a national market system. The proposed rule change is also consistent with Section 11A(a)(1) of the Act[6] in that it seeks to assure fair competition among brokers and dealers by providing IPO Auction functionality that is consistent with that of other market centers for which market participants have already designed their trading systems.[7] The Exchange believes that the proposed rule change promotes just and equitable principles of trade in that it promotes transparency and uniformity across markets concerning the eligibility of certain order types for IPO Auctions.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change imposes any burden on competition.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange has neither solicited nor received written comments on the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act[8] and Rule 19b–4(f)(6)(iii) thereunder.[9]

A proposed rule change filed under 19b-4(f)(6) normally may not become operative prior to 30 days after the date of filing.[10] However, Rule 19b–4(f)(6)(iii)[11] permits the Commission to designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange has requested that the Commission waive the 30-day operative delay. The Exchange notes that waiver of this requirement will allow the Exchange, before any future IPO Auctions, to harmonize with other market centers its rules regarding the eligibility of orders designated for participation in the Opening Auction for participation in IPO Auctions. The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest because such waiver would allow the Exchange to avoid confusion among its Members and would immediately provide certainty with respect to the Exchange's rules regarding participation in IPO auctions. For this reason, the Commission

[3] *See* Securities Exchange Act Release No. 65619 (October 25, 2011), 76 FR 67238 (October 31, 2011) (SR–BATS–2011–032).

[4] 15 U.S.C. 78f(b).

[5] 15 U.S.C. 78f(b)(5).

[6] 15 U.S.C. 78k–1(a)(1).

[7] *See* NYSE Arca Equities Rule 7.31(t). The Exchange is proposing to provide functionality analogous to that already available at NYSE Arca, which allows Auction-Only Orders, which consists of only MOO and LOO orders, to participate in the next auction that occurs after the order is entered. For example, a MOO or LOO order entered at NYSE Arca at any time will participate in the next occurring auction and the remaining non-executed shares are cancelled upon completion of the auction. The Exchange is proposing to apply this functionality only to IPO Auctions, while NYSE Arca applies the functionality to all auctions.

[8] 15 U.S.C. 78s(b)(3)(A).

[9] 17 CFR 240.19b–4(f)(6).

[10] 17 CFR 240.19b-4(f)(6)(iii). In addition, Rule 19b-4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[11] *Id.*

designates the proposed rule change to be operative upon filing with the Commission.[12]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an e-mail to *rule-comments@sec.gov.* Please include File Number SR–BATS–2012–009 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–BATS–2012–009. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10:00 a.m. and 3:00 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–BATS–2012–009 and should be submitted on or before March 8, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[13]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3609 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

[12] For the purposes only of waiving the 30-day operative delay, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[13] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66381; File No. SR–NYSEArca–2012–09]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing of Proposed Rule Change Relating to the Listing and Trading of the PIMCO Global Advantage Inflation-Linked Bond Strategy Fund Under NYSE Arca Equities Rule 8.600

February 10, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'' or ''Exchange Act'') [1] and Rule 19b–4 thereunder,[2] notice is hereby given that, on January 27, 2012, NYSE Arca, Inc. (''Exchange'' or ''NYSE Arca'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to list and trade the following under NYSE Arca Equities Rule 8.600 (''Managed Fund Shares''): PIMCO Global Advantage Inflation-Linked Bond Strategy Fund. The text of the proposed rule change is available at the Exchange, the Commission's Public Reference Room, and *www.nyse.com.*

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to list and trade the following Managed Fund Shares [3] (''Shares'') under NYSE Arca Equities Rule 8.600: PIMCO Global Advantage Inflation-Linked Bond Strategy Fund (''Fund'').[4] The Shares will be offered by PIMCO ETF Trust (''Trust''), a statutory trust organized under the laws of the State of Delaware and registered with the Commission as an open-end management investment company.[5]

[3] A Managed Fund Share is a security that represents an interest in an investment company registered under the Investment Company Act of 1940 (15 U.S.C. 80a–1) (''1940 Act'') organized as an open-end investment company or similar entity that invests in a portfolio of securities selected by its investment adviser consistent with its investment objectives and policies. In contrast, an open-end investment company that issues Investment Company Units, listed and traded on the Exchange under NYSE Arca Equities Rule 5.2(j)(3), seeks to provide investment results that correspond generally to the price and yield performance of a specific foreign or domestic stock index, fixed income securities index or combination thereof.

[4] The Commission has previously approved the listing and trading on the Exchange of other actively managed funds under Rule 8.600. *See, e.g.,* Securities Exchange Act Release Nos. 57801 (May 8, 2008), 73 FR 27878 (May 14, 2008) (SR–NYSEArca–2008–31) (order approving Exchange listing and trading of twelve actively-managed funds of the WisdomTree Trust); 60460 (August 7, 2009), 74 FR 41468 (August 17, 2009) (SR–NYSEArca–2009–55) (order approving Exchange listing and trading of AdvisorShares Dent Tactical ETF); 60981 (November 10, 2009), 74 FR 59594 (November 18, 2009) (SR–NYSEArca–2009–79) (order approving Exchange listing and trading of five fixed income funds of the PIMCO ETF Trust); 61365 (January 15, 2010), 75 FR 4124 (January 26, 2010) (SR–NYSEArca–2009–114) (order approving Exchange listing and trading of Grail McDonnell Fixed Income ETFs).

[5] The Trust is registered under the 1940 Act. On February 14, 2011, the Trust filed with the Commission Post-Effective Amendment No. 25 under the Securities Act of 1933 (15 U.S.C. 77a) (''Securities Act'') and Amendment No. 27 under

Continued

The investment manager to the Fund is Pacific Investment Management Company LLC (''PIMCO'' or ''Adviser''). PIMCO Investments LLC serves as the distributor for the Fund (''Distributor''). State Street Bank & Trust Co. serves as the custodian and transfer agent for the Fund (''Custodian'' or ''Transfer Agent'').

Commentary .06 to Rule 8.600 provides that, if the investment adviser to the investment company issuing Managed Fund Shares is affiliated with a broker-dealer, such investment adviser shall erect a ''fire wall'' between the investment adviser and the broker-dealer with respect to access to information concerning the composition and/or changes to such investment company portfolio.[6] In addition, Commentary .06 further requires that personnel who make decisions on the open-end fund's portfolio composition must be subject to procedures designed to prevent the use and dissemination of material nonpublic information regarding the open-end fund's portfolio. The Adviser is affiliated with a broker-dealer and has implemented a ''fire wall'' with respect to such broker-dealer regarding access to information concerning the composition and/or changes to the Fund's portfolio. If PIMCO elects to hire a sub-adviser for the Fund that is also affiliated with a broker-dealer, such sub-adviser will implement a fire wall with respect to such broker-dealer regarding access to information concerning the composition and/or changes to the portfolio. In the event (a) the Adviser or any sub-adviser becomes newly affiliated with a broker-dealer, or (b) any new adviser or sub-adviser becomes affiliated with a broker-dealer, it will implement a fire wall with respect to such broker-dealer regarding access to information concerning the composition and/or changes to the portfolio, and will be subject to procedures designed to prevent the use and dissemination of material non-public information regarding such portfolio.

According to the Registration Statement, the Fund seeks total return which exceeds that of its benchmark indexes, consistent with prudent investment management. The Fund's primary benchmark index is the Barclays Capital Universal Government Inflation-Linked Bond Index. The Fund's secondary benchmark index is the PIMCO Global Advantage Inflation-Linked Bond Index.

The Fund seeks to achieve its investment objective by investing under normal circumstances[7] at least 80% of its assets in a portfolio of inflation-linked bonds that is economically tied to at least three developed and/or emerging market countries (one of which may be the United States). The Fund's holdings may include bonds issued by issuers in both developed and/or emerging market countries and the Fund is expected to hold bonds of issuers that are economically tied[8] to many of the countries represented in the Fund's primary benchmark index.[9] Assets not invested in inflation-linked bonds may be invested in other types of Fixed Income Instruments.[10]

According to the Registration Statement, inflation-linked bonds are government-issued fixed income securities that are structured to provide protection against inflation. The value of the bond's principal or the interest income paid on the bond is adjusted to track changes in an official inflation measure. The effective duration of the Fund's portfolio normally varies within two years (plus or minus) of the effective duration of the PIMCO Global Advantage Inflation-Linked Bond Index which, as of September 30, 2011, as converted, was 4.53 years. Duration is a measure used to determine the sensitivity of a security's price to changes in interest rates. The longer a security's duration, the more sensitive it will be to changes in interest rates. Effective duration takes into account that, for certain bonds, expected cash flows will fluctuate as interest rates change and will be defined in nominal yield terms, which is market convention for most bond investors and managers. Because market convention for bonds is to use nominal yields to measure duration, duration for inflation-linked

the 1940 Act to the Trust's registration statement on Form N–1A relating to the Fund. On October 28, 2011, the Trust filed with the Commission Post-Effective Amendment No. 43 under the Securities Act and Amendment No. 45 under the 1940 Act to the Trust's registration statement on Form N–1A relating to the Fund (File Nos. 333–155395 and 811–22250) (''Registration Statement''). The description of the operation of the Trust and the Fund herein is based, in part, on the Registration Statement. In addition, the Commission has issued an order granting certain exemptive relief to the Trust under the 1940 Act. *See* Investment Company Act Release No. 28993 (November 10, 2009) (File No. 812–13571) (''Exemptive Order'').

[6] An investment adviser to an open-end fund is required to be registered under the Investment Advisers Act of 1940 (''Advisers Act''). As a result, the Adviser and its related personnel are subject to the provisions of Rule 204A–1 under the Advisers Act relating to codes of ethics. This Rule requires investment advisers to adopt a code of ethics that reflects the fiduciary nature of the relationship to clients as well as compliance with other applicable securities laws. Accordingly, procedures designed to prevent the communication and misuse of non-public information by an investment adviser must be consistent with Rule 204A–1 under the Advisers Act. In addition, Rule 206(4)–7 under the Advisers Act makes it unlawful for an investment adviser to provide investment advice to clients unless such investment adviser has (i) adopted and implemented written policies and procedures reasonably designed to prevent violation, by the investment adviser and its supervised persons, of the Advisers Act and the Commission rules adopted thereunder; (ii) implemented, at a minimum, an annual review regarding the adequacy of the policies and procedures established pursuant to subparagraph (i) above and the effectiveness of their implementation; and (iii) designated an individual (who is a supervised person) responsible for administering the policies and procedures adopted under subparagraph (i) above.

[7] The term ''under normal circumstances'' includes, but is not limited to, the absence of extreme volatility or trading halts in the fixed income markets or the financial markets generally; operational issues causing dissemination of inaccurate market information; or force majeure type events such as systems failure, natural or man-made disaster, act of God, armed conflict, act of terrorism, riot or labor disruption or any similar intervening circumstance.

[8] As disclosed in the Trust's Registration Statement, PIMCO generally considers an instrument to be economically tied to a non-U.S. country if the issuer is a foreign government (or any political subdivision, agency, authority or instrumentality of such government), or if the issuer is organized under the laws of a non-U.S. country. In the case of certain money market instruments, such instruments will be considered economically tied to a non-U.S. country if either the issuer or the guarantor of such money market instrument is organized under the laws of a non-U.S. country.

[9] Each country's approximate weighting within the global inflation-linked bond market, as reflected by the approximate weighting of the Barclays Capital Universal Government Inflation-Linked Bond Index (the Fund's primary benchmark), as of January 31, 2011, is as follows: U.S. 32%, U.K. 19%, France 11%, Brazil 10%, Italy 7%, Canada 2%, Germany 3%, Japan 3%, Mexico 2%, Sweden 2%, Turkey 2%, Argentina 1%, Australia 1%, Greece 1%, South Africa 1%, Chile <1%, Poland <1%, Colombia <1% and South Korea <1%. Each country's approximate value of outstanding inflation-linked bonds also as of January 31, 2011, is as follows (in $ billions): U.S. $642.7, U.K. $392.2, France $222.0, Brazil $209.6, Italy $143.2, Canada $49.9, Germany $60.9, Japan $57.0, Mexico $45.7, Sweden $39.1, Turkey $45.9, Argentina $20.0, Australia $17.7, Greece $11.8, South Africa $26.4, Chile $8.2, Poland $5.5, Colombia $2.7 and South Korea $3.4.

[10] The term ''Fixed Income Instruments'' includes: securities issued or guaranteed by the U.S. Government, its agencies or government-sponsored enterprises (''U.S. Government Securities''); corporate debt securities of U.S. and non-U.S. issuers, including convertible securities and corporate commercial paper; mortgage-backed and other asset-backed securities; inflation-indexed bonds issued both by governments and corporations; structured notes, including hybrid or ''indexed'' securities and event-linked bonds; bank capital and trust preferred securities; loan participations and assignments; delayed funding loans and revolving credit facilities; bank certificates of deposit, fixed time deposits and bankers' acceptances; repurchase agreements on Fixed Income Instruments and reverse repurchase agreements on Fixed Income Instruments; debt securities issued by states or local governments and their agencies, authorities and other government-sponsored enterprises; obligations of non-U.S. governments or their subdivisions, agencies and government-sponsored enterprises; and obligations of international agencies or supranational entities. Securities issued by U.S. Government agencies or government-sponsored enterprises may not be guaranteed by the U.S. Treasury.

bonds, which are based on real yields, are converted to nominal durations through a conversion factor. The resulting nominal duration typically can range from 20% to 90% of the respective real duration. All security holdings will be measured in effective (nominal) duration terms. Similarly, the effective duration of the PIMCO Global Advantage Inflation-Linked Bond Index will be calculated using the same conversion factors.

The Fund will invest under normal circumstances at least 80% of its assets in inflation-linked bonds issued by U.S. or foreign governments (or any political subdivision, agency, authority or instrumentality of such government).[11] The secondary benchmark includes a liquidity screen to remove inflation-linked bonds issued by governments of countries with cumulative inflation-linked bond issuances below $7 billion local currency equivalent, in addition to liquidity screens at the issue level. The global inflation-linked bond market exceeded $2.25 trillion as of December 31, 2011.[12]

The Fund primarily will invest in debt securities rated Baa or higher by Moody's Investors Service, Inc., or equivalently rated by Standard & Poor's Ratings Services or Fitch, Inc., or, if unrated, determined by PIMCO to be of comparable quality.[13] The Fund may obtain foreign currency exposure (from non-U.S. dollar denominated debt securities or currencies) without limitation. The Fund may purchase and sell debt securities on a when-issued, delayed delivery or forward commitment basis. The Fund may, without limitation, seek to obtain market exposure to the securities in which it primarily invests by entering into a series of purchase and sale contracts or by using other investment techniques (such as buy backs or dollar rolls). The Fund may invest, without limitation, in debt securities and instruments of foreign government issuers, including debt securities and instruments economically tied to emerging market countries.

Other Portfolio Holdings

The Fund's portfolio holdings will be disclosed on the Trust's Web site (*www.pimcoetfs.com*) daily after the close of trading on the Exchange and prior to the opening of trading on the Exchange the following day.

As disclosed in the Trust's Registration Statement, if PIMCO believes that economic or market conditions are unfavorable to investors, PIMCO may temporarily invest up to 100% of the Fund's assets in certain defensive strategies, including holding a substantial portion of the Fund's assets in cash, cash equivalents or other highly rated short-term securities, including securities issued or guaranteed by the U.S. government, its agencies or instrumentalities and affiliated money market and/or short-term bond funds.

The Fund may invest in, to the extent permitted by Section 12(d)(1) of the 1940 Act and rules thereunder, other affiliated and unaffiliated funds, such as open-end or closed-end management investment companies, including other exchange traded funds.

The Fund may enter into foreign currency transactions (such as currency forwards).[14]

The Fund may hold in the aggregate up to 15% of its net assets in: (1) Illiquid securities,[15] which include delayed funding loans, revolving credit facilities, fixed- and floating-rate loans and loan participations and assignments, and (2) Rule 144A securities. Certain illiquid securities may require pricing at fair value as determined in good faith under the supervision of the Fund's Board of Trustees. The term ''illiquid securities'' for this purpose means securities that cannot be disposed of within seven days in the ordinary course of business at approximately the amount at which the Fund has valued the securities.

With respect to its equity securities investments, the Fund will invest only in U.S.-registered equity securities and non-U.S.-registered equity securities that trade in markets that are members of the Intermarket Surveillance Group (''ISG'') or are parties to a comprehensive surveillance sharing agreement with the Exchange.[16]

Investment Limitations

The Fund is subject to the following investment limitations:

The Fund may not concentrate its investments in a particular industry, as that term is used in the 1940 Act,[17] and as interpreted, modified, or otherwise permitted by regulatory authority having jurisdiction from time to time.[18]

The Fund will be non-diversified,[19] which means that it may invest its assets in a smaller number of issuers than a diversified fund.[20]

[11] According to the Registration Statement, the value of inflation-linked bonds is expected to change in response to changes in real interest rates. Real interest rates are tied to the relationship between nominal interest rates and the rate of inflation. If nominal interest rates increase at a faster rate than inflation, real interest rates may rise, leading to a decrease in value of inflation-linked bonds.

[12] The value of the global inflation-linked bond market is calculated based on the total outstanding value of issues included in the Barclays Capital Universal Government Inflation-Linked Bond Index that are not expiring in less than one year.

[13] The Adviser represents that, in selecting securities for the Fund, PIMCO will develop an outlook for interest rates, currency exchange rates and the economy, analyze credit and call risks, and use other security selection techniques. The proportion of the Fund's assets committed to investment in securities with particular characteristics (such as quality, sector, interest rate or maturity) will vary based on PIMCO's outlook for the U.S. economy and the economies of other countries in the world, the financial markets and other factors. Sophisticated proprietary software will assist in evaluating sectors, pricing and rating specific securities. Once investment opportunities are identified, PIMCO will shift assets among sectors and securities depending upon changes in relative valuations and credit spreads in a manner consistent with the Fund's objective and strategies. To the extent the Fund invests in unrated securities that PIMCO determines to be of comparable quality to rated securities that the Fund may purchase, the Fund's ability to achieve its objective may depend more heavily on PIMCO's creditworthiness analysis than if the Fund invested exclusively in rated securities.

[14] The Fund may engage in these transactions primarily to: (1) Protect against uncertainty in the level of future foreign exchange rates in the purchase and sale of securities; or (2) lower currency deviations relative to the Fund's benchmark indexes.

[15] The Commission has stated that long-standing Commission guidelines have required open-end funds to hold no more than 15% of their net assets in illiquid securities and other illiquid assets. *See* Investment Company Act Release No. 28193 (March 11, 2008), 73 FR 14617 (March 18, 2008), footnote 34. *See also* Investment Company Act Release No. 5847 (October 21, 1969), 35 FR 19989 (December 31, 1970) (Statement Regarding ''Restricted Securities''); Investment Company Act Release No. 18612 (March 12, 1992), 57 FR 9828 (March 20, 1992) (Revisions of Guidelines to Form N–1A). A fund's portfolio security is illiquid if it cannot be disposed of in the ordinary course of business within seven days at approximately the value ascribed to it by the ETF. *See* Investment Company Act Release No. 14983 (March 12, 1986), 51 FR 9773 (March 21, 1986) (adopting amendments to Rule 2a–7 under the 1940 Act); Investment Company Act Release No. 17452 (April 23, 1990), 55 FR 17933 (April 30, 1990) (adopting Rule 144A under the Securities Act).

[16] *See* note 29, *infra.*

[17] *See* Form N–1A, Item 9. The Commission has taken the position that a fund is concentrated if it invests more than 25% of the value of its total assets in any one industry. *See, e.g.,* Investment Company Act Release No. 9011 (October 30, 1975), 40 FR 54241 (November 21, 1975).

[18] The Fund's policy with respect to the concentration of investments in a particular industry is disclosed in the Trust's Registration Statement.

[19] A ''non-diversified company'', as defined in Section 5(b)(2) of the 1940 Act, means any management company other than a diversified company (as defined in Section 5(b)(1) of the 1940 Act).

[20] The minimum number of inflation-linked bonds and other Fixed Income Instruments and issuers in which the Fund may invest at any one time depends in part upon the number of securities or issuers comprising the Fund's benchmark indexes. In seeking to achieve its investment objective, the Fund's portfolio will consist of at least twenty-five (25) inflation-linked bonds and other Fixed Income Instruments on any given day, but the Fund may regularly invest in fifty (50) or more inflation-linked bonds and other Fixed Income Instruments at a time in seeking to achieve

Continued

The Fund intends to qualify annually and elect to be treated as a regulated investment company under Subchapter M of the Internal Revenue Code.[21]

Consistent with the Exemptive Order, the Fund will not invest in options contracts, futures contracts or swap agreements.

The Fund's investments will be consistent with the Fund's investment objective and will not be used to enhance leverage. That is, while the Fund will be permitted to borrow as permitted under the 1940 Act, the Fund's investments will not be used to seek performance that is the multiple or inverse multiple (*i.e.,* 2Xs and 3Xs) of the Fund's primary broad-based securities benchmark index (as defined in Form N–1A) (*i.e.,* the Barclays Capital Universal Government Inflation-Linked Bond Index).

The Shares will conform to the initial and continued listing criteria under NYSE Arca Equities Rule 8.600. The Exchange represents that, for initial and/or continued listing, the Fund will be in compliance with Rule 10A–3 under the Exchange Act,[22] as provided by NYSE Arca Equities Rule 5.3. A minimum of 100,000 Shares will be outstanding at the commencement of trading on the Exchange. The Exchange will obtain a representation from the issuer of the Shares that the net asset value (''NAV'') per Share will be calculated daily and that the NAV and the Disclosed Portfolio will be made available to all market participants at the same time.

Creations and Redemptions of Shares

According to the Registration Statement, Shares of the Fund that trade in the secondary market will be ''created'' at NAV[23] by Authorized Participants only in block-size Creation Units of 100,000 Shares or multiples thereof. The Fund will offer and issue Shares at their NAV per Share generally in exchange for a basket of debt securities held by the Fund (''Deposit Securities'') together with a deposit of a specified cash payment (''Cash Component''). Alternatively, the Fund may issue Creation Units in exchange for a specified all-cash payment (''Cash Deposit''). Similarly, Shares can be redeemed only in Creation Units, generally in-kind for a portfolio of debt securities held by the Fund and/or for a specified amount of cash.

Except when aggregated in Creation Units, Shares will not be redeemable by the Fund. The prices at which creations and redemptions occur will be based on the next calculation of NAV after an order is received. Requirements as to the timing and form of orders are described in the Authorized Participant agreement. PIMCO will make available on each business day via the National Securities Clearing Corporation (''NSCC'') or other method of public dissemination, prior to the opening of business (subject to amendments) on the Exchange (currently 9:30 a.m. E.T.), the identity and the required amount of each Deposit Security and the amount of the Cash Component (or Cash Deposit) to be included in the current Fund Deposit[24] (based on information at the end of the previous business day). Creations and redemptions must be made by an Authorized Participant or through a firm that is either a participant in the Continuous Net Settlement System of the NSCC or a DTC participant, and in each case, must have executed an agreement with the Distributor and Transfer Agent with respect to creations and redemptions of Creation Unit aggregations.

Additional information regarding the Trust and the Shares, including investment strategies, risks, creation and redemption procedures, fees, portfolio holdings, disclosure policies, distributions and taxes is included in the Registration Statement. All terms relating to the Fund that are referred to but not defined in this proposed rule change are defined in the Registration Statement.

Availability of Information

The Trust's Web site (*www.pimcoetfs.com*), which will be publicly available prior to the public offering of Shares, will include a form of the prospectus for the Fund that may be downloaded. The Trust's Web site will include additional quantitative information updated on a daily basis, including, for the Fund, (1) daily trading volume, the prior business day's reported closing price, NAV and mid-point of the bid/ask spread at the time of calculation of such NAV (''Bid/Ask Price''),[25] and a calculation of the premium and discount of the Bid/Ask Price against the NAV, and (2) data in chart format displaying the frequency distribution of discounts and premiums of the daily Bid/Ask Price against the NAV, within appropriate ranges, for each of the four previous calendar quarters. On each business day, before commencement of trading in Shares in the Core Trading Session (9:30 a.m. E.T. to 4:00 p.m. E.T.) on the Exchange, the Fund will disclose on the Trust's Web site the Disclosed Portfolio as defined in NYSE Arca Equities Rule 8.600(c)(2) that will form the basis for the Fund's calculation of NAV at the end of the business day.[26]

On a daily basis, the Adviser will disclose for each portfolio security or other financial instrument of the Fund the following information: Ticker symbol (if applicable), name of security or financial instrument, number of shares or dollar value of financial instruments held in the portfolio, and percentage weighting of the security or financial instrument in the portfolio. The Web site information will be publicly available at no charge. In addition, price information for the debt

its investment objective. The Fund's portfolio will hold issues of at least 13 non-affiliated issuers.

[21] 26 U.S.C. 851. To qualify as a regulated investment company, the Fund generally must, among other things, (a) derive in each taxable year at least 90% of its gross income from dividends, interest, payments with respect to securities loans, and gains from the sale or other disposition of stock, securities or foreign currencies, net income from certain ''qualified publicly traded partnerships,'' or other income derived with respect to its business of investing in such stock, securities or currencies (''Qualifying Income Test''); (b) diversify its holdings so that, at the end of each quarter of the taxable year, (i) at least 50% of the market value of the Fund's assets is represented by cash, U.S. Government securities, the securities of other regulated investment companies and other securities, with such other securities of any one issuer limited for the purposes of this calculation to an amount not greater than 5% of the value of the Fund's total assets and 10% of the outstanding voting securities of such issuer, and (ii) not more than 25% of the value of its total assets is invested in the securities of any one issuer (other than U.S. Government securities or the securities of other regulated investment companies), the securities of certain controlled issuers in the same or similar trades or businesses, or the securities of one or more ''qualified publicly traded partnerships''; and (c) distribute each taxable year the sum of (i) at least 90% of its investment company taxable income (which includes dividends, interest and net short-term capital gains in excess of any net long-term capital losses) and (ii) 90% of its tax exempt interest, net of expenses allocable thereto.

[22] 17 CFR 240.10A–3.

[23] The NAV of the Fund's Shares generally will be calculated once daily Monday through Friday as of the close of regular trading on the New York Stock Exchange (''NYSE''), generally 4 p.m. Eastern time (''E.T.'') (''NAV Calculation Time'') on any business day. NAV per Share will be calculated by dividing the Fund's net assets by the number of Fund Shares outstanding. For more information regarding the valuation of Fund investments in calculating the Fund's NAV, see the Registration Statement.

[24] The Deposit Securities and Cash Component or, alternatively, the Cash Deposit, constitute the ''Fund Deposit,'' which represents the investment amount for a Creation Unit of the Fund.

[25] The Bid/Ask Price of the Fund is determined using the midpoint of the highest bid and the lowest offer on the Exchange as of the time of calculation of the Fund's NAV. The records relating to Bid/Ask Prices will be retained by the Fund and its service providers.

[26] Under accounting procedures followed by the Fund, trades made on the prior business day (''T'') will be booked and reflected in NAV on the current business day (''T+1''). Accordingly, the Fund will be able to disclose at the beginning of the business day the portfolio that will form the basis for the NAV calculation at the end of the business day.

securities held by the Fund will be available through major market data vendors.

In addition, a basket composition file, which will include the security names and share quantities, if applicable, required to be delivered in exchange for Fund Shares, together with estimates and actual cash components, will be publicly disseminated daily prior to the opening of the NYSE via the NSCC. The basket represents one Creation Unit of the Fund. The NAV of the Fund will normally be determined as of the close of the regular trading session on the NYSE (ordinarily 4 p.m. E.T.) on each business day. Authorized Participants may refer to the basket composition file for information regarding Fixed Income Instruments, inflation-linked bonds and any other instrument that may comprise the Fund's basket on a given day.

Investors can also obtain the Trust's Statement of Additional Information (''SAI''), the Fund's Shareholder Reports, and its Form N–CSR and Form N–SAR, filed twice a year. The Trust's SAI and Shareholder Reports are available free upon request from the Trust, and those documents and the Form N–CSR and Form N–SAR may be viewed on-screen or downloaded from the Commission's Web site at *www.sec.gov*. Information regarding market price and trading volume of the Shares will be continually available on a real-time basis throughout the day on brokers' computer screens and other electronic services. Information regarding the previous day's closing price and trading volume information for the Shares will be published daily in the financial section of newspapers. Quotation and last sale information for the Shares will be available via the Consolidated Tape Association (''CTA'') high-speed line. In addition, the Portfolio Indicative Value, as defined in NYSE Arca Equities Rule 8.600(c)(3), will be widely disseminated by one or more major market data vendors at least every 15 seconds during the Core Trading Session.[27] The dissemination of the Portfolio Indicative Value, together with the Disclosed Portfolio, will allow investors to determine the value of the underlying portfolio of the Fund on a daily basis and to provide a close estimate of that value throughout the trading day.

Trading Halts

With respect to trading halts, the Exchange may consider all relevant factors in exercising its discretion to halt or suspend trading in the Shares of the Fund.[28] Trading in Shares of the Fund will be halted if the circuit breaker parameters in NYSE Arca Equities Rule 7.12 have been reached. Trading also may be halted because of market conditions or for reasons that, in the view of the Exchange, make trading in the Shares inadvisable. These may include: (1) The extent to which trading is not occurring in the securities and/or the financial instruments comprising the Disclosed Portfolio of the Fund; or (2) whether other unusual conditions or circumstances detrimental to the maintenance of a fair and orderly market are present. Trading in the Shares will be subject to NYSE Arca Equities Rule 8.600(d)(2)(D), which sets forth circumstances under which Shares of the Fund may be halted.

Trading Rules

The Exchange deems the Shares to be equity securities, thus rendering trading in the Shares subject to the Exchange's existing rules governing the trading of equity securities. Shares will trade on the NYSE Arca Marketplace from 4 a.m. to 8 p.m. E.T. in accordance with NYSE Arca Equities Rule 7.34 (Opening, Core, and Late Trading Sessions). The Exchange has appropriate rules to facilitate transactions in the Shares during all trading sessions. As provided in NYSE Arca Equities Rule 7.6, Commentary .03, the minimum price variation (''MPV'') for quoting and entry of orders in equity securities traded on the NYSE Arca Marketplace is $0.01, with the exception of securities that are priced less than $1.00 for which the MPV for order entry is $0.0001.

Surveillance

The Exchange intends to utilize its existing surveillance procedures applicable to derivative products (which include Managed Fund Shares) to monitor trading in the Shares. The Exchange represents that these procedures are adequate to properly monitor Exchange trading of the Shares in all trading sessions and to deter and detect violations of Exchange rules and applicable federal securities laws.

The Exchange's current trading surveillance focuses on detecting securities trading outside their normal patterns. When such situations are detected, surveillance analysis follows and investigations are opened, where appropriate, to review the behavior of all relevant parties for all relevant trading violations.

The Exchange may obtain information via the ISG from other exchanges that are members of ISG or with which the Exchange has in place a comprehensive surveillance sharing agreement.[29]

In addition, the Exchange also has a general policy prohibiting the distribution of material, non-public information by its employees.

Information Bulletin

Prior to the commencement of trading, the Exchange will inform its Equity Trading Permit (''ETP'') Holders in an Information Bulletin (''Bulletin'') of the special characteristics and risks associated with trading the Shares. Specifically, the Bulletin will discuss the following: (1) The procedures for purchases and redemptions of Shares in Creation Unit aggregations (and that Shares are not individually redeemable); (2) NYSE Arca Equities Rule 9.2(a), which imposes a duty of due diligence on its ETP Holders to learn the essential facts relating to every customer prior to trading the Shares; (3) the risks involved in trading the Shares during the Opening and Late Trading Sessions when an updated Portfolio Indicative Value will not be calculated or publicly disseminated; (4) how information regarding the Portfolio Indicative Value is disseminated; (5) the requirement that ETP Holders deliver a prospectus to investors purchasing newly issued Shares prior to or concurrently with the confirmation of a transaction; and (6) trading information.

In addition, the Bulletin will reference that the Fund is subject to various fees and expenses described in the Registration Statement. The Bulletin will discuss any exemptive, no-action, and interpretive relief granted by the Commission from any rules under the Exchange Act. The Bulletin will also disclose that the NAV for the Shares will be calculated after 4:00 p.m. E.T. each trading day.

2. Statutory Basis

The basis under the Exchange Act for this proposed rule change is the requirement under Section 6(b)(5)[30] that an exchange have rules that are designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to remove impediments to, and perfect the mechanism of a free and

[27] Currently, it is the Exchange's understanding that several major market data vendors display and/or make widely available Portfolio Indicative Values published on CTA or other data feeds.

[28] *See* NYSE Arca Equities Rule 7.12, Commentary .04.

[29] For a list of the current members of ISG, see *www.isgportal.org*. The Exchange notes that not all components of the Disclosed Portfolio for the Fund may trade on markets that are members of ISG or with which the Exchange has in place a comprehensive surveillance sharing agreement.

[30] 15 U.S.C. 78f(b)(5).

open market and, in general, to protect investors and the public interest.

The Exchange believes that the proposed rule change is designed to prevent fraudulent and manipulative acts and practices in that the Shares will be listed and traded on the Exchange pursuant to the initial and continued listing criteria in NYSE Arca Equities Rule 8.600. The Exchange has in place surveillance procedures that are adequate to properly monitor trading in the Shares in all trading sessions and to deter and detect violations of Exchange rules and applicable federal securities laws. The Exchange may obtain information via ISG from other exchanges that are members of ISG or with which the Exchange has entered into a comprehensive surveillance sharing agreement. According to the Registration Statement, the Fund will invest under normal circumstances at least 80% of its assets in inflation-linked bonds issued by U.S. or foreign governments, screened for minimum liquidity levels. The Fund primarily will invest in debt securities rated Baa or higher by Moody's Investors Service, Inc., or equivalently rated by Standard & Poor's Ratings Services or Fitch, Inc., or, if unrated, determined by PIMCO to be of comparable quality. The Adviser is affiliated with a broker-dealer and has implemented a ''fire wall'' with respect to such broker-dealer regarding access to information concerning the composition and/or changes to the Fund's portfolio. In addition, the Fund will implement and maintain, or be subject to, procedures designed to prevent the use and dissemination of material non-public information regarding the Fund's portfolio holdings. Consistent with the Exemptive Order, the Fund will not invest in options contracts, futures contracts or swap agreements. The Fund's investments will be consistent with the Fund's investment objective and will not be used to enhance leverage. That is, while the Fund will be permitted to borrow as permitted under the 1940 Act, the Fund's investments will not be used to seek performance that is the multiple or inverse multiple (*i.e.,* 2Xs and 3Xs) of the Fund's primary broad-based securities benchmark index (as defined in Form N–1A) (*i.e.,* the Barclays Capital Universal Government Inflation-Linked Bond Index).

The proposed rule change is designed to promote just and equitable principles of trade and to protect investors and the public interest in that the Exchange will obtain a representation from the issuer of the Shares that the NAV per Share will be calculated daily and that the NAV and the Disclosed Portfolio will be made available to all market participants at the same time. In addition, a large amount of information is publicly available regarding the Fund and the Shares, thereby promoting market transparency. The Fund's portfolio holdings will be disclosed on the Trust's Web site daily after the close of trading on the Exchange and prior to the opening of trading on the Exchange the following day. Moreover, the Portfolio Indicative Value will be widely disseminated by one or more major market data vendors at least every 15 seconds during the Exchange's Core Trading Session. On each business day, before commencement of trading in Shares in the Core Trading Session on the Exchange, the Fund will disclose on the Trust's Web site the Disclosed Portfolio that will form the basis for the Fund's calculation of NAV at the end of the business day. Information regarding market price and trading volume of the Shares will be continually available on a real-time basis throughout the day on brokers' computer screens and other electronic services, and quotation and last sale information will be available via the CTA high-speed line. The Trust's Web site will include a form of the prospectus for the Fund and additional data relating to NAV and other applicable quantitative information. Moreover, prior to the commencement of trading, the Exchange will inform its ETP Holders in an Information Bulletin of the special characteristics and risks associated with trading the Shares. Trading in Shares of the Fund will be halted if the circuit breaker parameters in NYSE Arca Equities Rule 7.12 have been reached or because of market conditions or for reasons that, in the view of the Exchange, make trading in the Shares inadvisable, and trading in the Shares will be subject to NYSE Arca Equities Rule 8.600(d)(2)(D), which sets forth circumstances under which Shares of the Fund may be halted. In addition, as noted above, investors will have ready access to information regarding the Fund's holdings, the Portfolio Indicative Value, the Disclosed Portfolio, and quotation and last sale information for the Shares.

The proposed rule change is designed to perfect the mechanism of a free and open market and, in general, to protect investors and the public interest in that it will facilitate the listing and trading of an additional type of actively-managed exchange-traded product that will enhance competition among market participants, to the benefit of investors and the marketplace. As noted above, the Exchange has in place surveillance procedures relating to trading in the Shares and may obtain information via ISG from other exchanges that are members of ISG or with which the Exchange has entered into a comprehensive surveillance sharing agreement. In addition, as noted above, investors will have ready access to information regarding the Fund's holdings, the Portfolio Indicative Value, the Disclosed Portfolio, and quotation and last sale information for the Shares.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

(A) By order approve or disapprove such proposed rule change, or

(B) Institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml);* or
- Send an email to *rule-comments@sec.gov*. Please include File Number SR–NYSEArca–2012–09 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEArca–2012–09. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml).* Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEArca–2012–09 and should be submitted on or before March 8, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[31]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3610 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

[31] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66371; File No. SR–NYSEAmex–2011–101]

Self-Regulatory Organizations; NYSE Amex LLC.; Order Granting Approval of Proposed Rule Change Amending NYSE Amex Equities Rules 504 and 509 To Modify the Quoting Requirements Applicable to Designated Market Maker Units Registered in Nasdaq Stock Market Securities Traded on the Exchange Subject to the Unlisted Trading Privileges Pilot Program

February 10, 2012.

I. Introduction

On December 15, 2011, NYSE Amex LLC (''NYSE Amex'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] a proposed rule change to modify the quoting requirements applicable to Designated Market Maker (''DMM'') units registered in Nasdaq Stock Market securities traded on the Exchange pursuant to a grant of unlisted trading privileges (''UTP''). The proposed rule change was published for comment in the **Federal Register** on December 30, 2011.[3] The Commission received no comment letters on the proposal. This order approves the proposed rule change.

II. Description of the Proposal

Certain securities listed on Nasdaq may be traded on NYSE Amex pursuant to a grant of unlisted trading privileges as part of a pilot program on the Exchange (''UTP Pilot Program'').[4] NYSE Amex's proposal seeks to modify the UTP Pilot Program's obligations imposed on DMM units who quote in such securities.

Currently, under NYSE Amex Equities Rule 509(a)(1), DMM units who are registered in securities subject to the UTP Pilot Program must maintain continuous two-sided quotes at the National Best Bid or Offer (''NBBO'') with reasonable size for each such security for at least 10% of the time during the regular business hours of the Exchange for each calendar month.[5] The proposal would amend NYSE Amex Equities Rule 509(a)(1) to lower a DMM unit's quoting obligations for ''more active''[6] securities in the UTP Pilot Program from at least 10% of the time during the regular trading day to at least 5% of the time during the regular trading day.[7] The proposed quoting obligations would continue to apply on a security-by-security basis. The current quoting obligation for ''less active'' securities, *i.e.,* those with a consolidated average daily volume of less than one million shares per calendar month, would remain unchanged at 10% of the time during the regular trading day.

The Exchange also proposes to delete from NYSE Amex Equities Rule 504(b)(1)(A) the text that references NYSE Amex Equities Rule 103B(II), which provides for security allocation eligibility. The Exchange represented that this reference is not necessary within Rule 504(b)(1)(A), and that, despite the proposed deletion, DMM units would remain subject to NYSE Amex Equities Rule 103B(II) with respect to security allocation eligibility.

III. Discussion and Commission Findings

After careful review, the Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder that are applicable to a national securities exchange, and, in particular, with the requirements of Section 6(b) of the Act.[8] In particular, the proposed change is consistent with Section 6(b)(5) of the Act,[9] because it would promote just and equitable principles of trade, and, in general, protect investors and the public interest.[10] The Commission also finds that the proposed rule change is consistent with Section 12(f) of the Act,[11] because it furthers the goals of maintaining fair and orderly markets, and protecting investors and the public

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] Securities Exchange Act Release No. 66043 (December 23, 2011), 76 FR 82329 (''Notice'').

[4] The UTP Pilot Program is scheduled to expire on the earlier of Commission approval to make such pilot permanent or July 31, 2012. *See* Securities Exchange Act Release No. 66040 (December 23, 2011), 76 FR 82324 (December 30, 2011).

[5] These obligations are also included within current NYSE Amex Equities Rule 504.

[6] Under NYSE Amex Equities Rule 103B(II)(C), ''more active'' securities are those with a consolidated average daily volume equal to or greater than one million shares per calendar month.

[7] The Exchange proposed to make conforming changes to NYSE Amex Equities Rule 504(b)(1)(A), which contains a requirement similar to NYSE Amex Equities Rule 509(a)(1) requiring DMM Units to quote at the NBBO on average at least 10% of the trading day.

[8] 15 U.S.C. 78f(b).

[9] 15 U.S.C. 78f(b)(5).

[10] In approving the proposed rule change, the Commission notes that it has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

[11] 15 U.S.C. 78l(f).

interest, for securities traded pursuant to UTP.

The Exchange proposes to reduce DMM units' quoting obligations applicable to ''more active'' securities traded in the UTP Pilot Program to quoting at the NBBO for 5% of the trading day. The Commission notes that this percentage would reflect the quoting requirement currently applicable to DMM units quoting non-UTP Pilot Program securities, *i.e.,* those listed on the Exchange.[12] There would be one significant difference between the proposed quoting obligation for the UTP Pilot Program and the current quoting obligation for non-UTP Pilot Program securities—UTP Pilot Program quoting obligations are and would continue to be calculated on a security-by-security basis, rather than averaged across a portfolio of all of a DMM unit's assigned securities. The Commission believes that this security-by-security basis calculation is reasonably designed to maintain robust quotes for all UTP Pilot Program securities. In addition, the Exchange's proposal would reduce quoting obligations only for ''more active'' securities, which by definition are more liquid and may, therefore, be less reliant on quoting obligations for continued liquidity. Finally, based on the Exchange's experience during the UTP Pilot Program, the proposed quoting obligation is designed to ensure the continued active participation by DMM units in such securities.

The Commission also finds that the proposed deletion in NYSE Amex Equities Rule 504(b)(1)(A) to the reference to NYSE Amex Equities Rule 103B(II) is consistent with the Act. The Exchange represented that this reference is not necessary within Rule 504(b)(1)(A), and that, despite the proposed deletion, DMM units would remain subject to NYSE Amex Equities Rule 103B(II) with respect to security allocation eligibility.

For the foregoing reasons, the Commission finds that the proposal to amend the UTP Pilot Program is consistent with the requirements of the Act.

IV. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[13] that the proposed rule change (SR–NYSEAmex–2011–101) be, and it hereby is, approved.

[12] *See* NYSE Amex Equities Rule 104(a)(1)(A).

[13] 15 U.S.C. 78s(b)(2).

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[14]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3611 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

[14] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66377; File No. SR–NYSEArca–2012–12]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Implementing Changes to the NYSE Arca Options Fee Schedule Relating to Post Liquidity Credits

February 10, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] notice is hereby given that, on January 31, 2012, NYSE Arca, Inc. (the ''Exchange'' or ''NYSE Arca'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend the NYSE Arca Options Fee Schedule (''Fee Schedule'') to increase the Post Liquidity credits on Customer posted electronic executions and to delete references to Royalty Fees for foreign currency options, which the Exchange no longer trades. The text of the proposed rule change is available at the Exchange, the Commission's Public Reference Room, and *www.nyse.com.*

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend the Fee Schedule to increase the Post Liquidity credits on Customer posted electronic executions and to delete references to Royalty Fees for foreign currency options, which the Exchange no longer trades. The Exchange proposes to make the rule change operative on February 1, 2012.

Post Liquidity Credits

Electronic transactions in Penny Pilot issues[3] are assessed Take Liquidity fees and credited with Post Liquidity credits. Under the current Fee Schedule, the Post Liquidity credit is $0.25 per contract for Customers, $0.32 per contract for Lead Market Makers and Market Makers, and $0.10 per contract for Firms and Broker Dealers. OTP Holders that provide aggregated Customer posting volume in Penny Pilot issues that exceeds certain thresholds receive higher Post Liquidity credits on all Customer posted electronic executions. Specifically, an OTP Holder sending Customer orders that in the aggregate exceed 500,000 contracts executed in a month from posting liquidity receives a Post Liquidity credit of $0.32 per contract on all executions resulting from posted liquidity. If such aggregated Customer orders exceed 800,000 contracts executed in a month from posting liquidity, the OTP Holder receives a Post Liquidity credit of $0.34 per contract on all executions resulting from posted liquidity. If such aggregated Customer orders exceed 1,200,000 contracts executed in a month from posting liquidity, the OTP Holder receives a Post Liquidity credit of $0.38 per contract on all executions resulting from posted liquidity. The volume thresholds are intended to incentivize firms to route additional Customer orders to the Exchange.

The Exchange proposes to amend the volume thresholds for the Post Liquidity credits by lowering the initial volume threshold to qualify for the first level of higher Post Liquidity credits, generally raising the amount of the Post Liquidity

[3] Under NYSE Arca Options Rule 6.72, options on certain issues have been approved to trade in a minimum price variation of $0.01 as part of a pilot program that is scheduled to expire on June 30, 2012.

credits for the next two volume thresholds, and creating a new higher volume threshold that will pay a higher Post Liquidity credit than is currently offered. The Exchange notes, however, that under the proposed volume thresholds, an OTP Holder that sends Customer orders that in the aggregate exceed 500,000 but not 800,000 contracts executed in a month will receive a lower Post Liquidity credit of $0.28 per contract, which is lower than the $0.32 Post Liquidity credit under the current Fee Schedule. The Exchange believes that the overall redistribution of the credits will in turn increase order flow to add liquidity on the Exchange and encourage greater participation by the largest market participants. The proposed volume thresholds and Post Liquidity credits are as follows:

	Monthly total customer contracts executed from posted liquidity	Per contract rate on all posted liquidity
Threshold 1	More than 350,000	−$0.28
Threshold 2	More than 800,000	−0.36
Threshold 3	More than 1,200,000	−0.42
Threshold 4	More than 3,500,000	−0.43

Royalty Fees for Foreign Currency Options

The current Fee Schedule sets forth Royalty Fees for certain foreign currency options. Because the Exchange no longer trades foreign currency options, it proposes to delete references to such Royalty Fees.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with Section 6(b) of the Securities Exchange Act of 1934 (the ''Act'') [4] in general and Section 6(b)(4) of the Act [5] in particular because it is designed to provide for the equitable allocation of reasonable dues, fees, and other charges among its members and other persons using its facilities and does not unfairly discriminate between customers, issuers, brokers or dealers. The proposed change is equitably allocated and not unfairly discriminatory because it will apply uniformly to all similarly situated OTP Holders that direct Customer orders to the Exchange. The proposed fees also are equitably allocated and reasonable because they create an incrementally higher incentive for OTP Holders to bring additional liquidity to the Exchange, thereby contributing to price discovery and benefiting investors generally. Moreover, the difference between (1) the Post Liquidity credits received by OTP Holders that aggregate Customer orders, and (2) the Post Liquidity credit received by Firms and Broker Dealers is not inequitable or unfairly discriminatory because the Exchange believes that it has structured its Fee Schedule in a manner to attract order flow from all such entities. In this regard, the Exchange has found that the higher Post Liquidity credit for Firms and Broker Dealers has not caused them to send additional order flow to the Exchange. Based on its observations, the Exchange believes that such entities focus on the ability to trade with Customer order flow to capture the spread rather than on rebates and fees. Accordingly, the Exchange is proposing to further generally increase the Post Liquidity credits for Customer order flow to attract such order flow to the Exchange. Although certain OTP Holders that send Customer orders that in the aggregate exceed 500,000 but not 800,000 contracts executed in a month will receive a slightly lower Post Liquidity credit than they currently do, other OTP Holders that previously did not qualify for the credit will qualify going forward. The Exchange believes that overall redistribution of the credits will in turn increase order flow to add liquidity on the Exchange and encourage greater participation by the largest market participants. With the anticipated increase in such order flow to the Exchange, the Exchange expects to attract additional order flow from Firms and Broker Dealers to trade with such order flow. The Exchange further believes that the proposed change is reasonable because other exchanges offer comparable tiers of credits for adding Customer liquidity in Penny Pilot issues.[6]

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change is effective upon filing pursuant to Section 19(b)(3)(A) [7] of the Act and subparagraph (f)(2) of Rule 19b–4 [8] thereunder, because it establishes a due, fee, or other charge imposed by the NYSE Arca.

At any time within 60 days of the filing of such proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–NYSEArca–2012–12 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary,

[4] 15 U.S.C. 78f(b).

[5] 15 U.S.C. 78f(b)(4).

[6] *See, e.g.,* Nasdaq Options Market pricing, available at *http://nasdaqtrader.com/Micro.aspx?id=OptionsPricing,* and BATS BZX Exchange Fee Schedule, Effective January 3, 2012, available at *http://batstrading.com/FeeSchedule/.*

[7] 15 U.S.C. 78s(b)(3)(A).

[8] 17 CFR 240.19b–4(f)(2).

Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEArca-2012–12. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10:00 a.m. and 3:00 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEArca–2012–12 and should be submitted on or before March 8, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[9]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3613 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

[9] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66372; File No. SR–NASDAQ–2012–021]

Self-Regulatory Organizations; Notice of Filing and Immediate Effectiveness of Proposed Rule Change by NASDAQ Stock Market LLC Relating to Fidelity Bonds

February 10, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4[2] thereunder, notice is hereby given that on January 31, 2012, The NASDAQ Stock Market LLC (''NASDAQ'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I and II below, which Items have been prepared by NASDAQ. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The NASDAQ Stock Market LLC proposes to amend NASDAQ Rule 3020 to reflect recent changes to a corresponding rule of the Financial Industry Regulatory Authority (''FINRA'').

The text of the proposed rule change is available on the Exchange's Web site at *http://www.nasdaq.cchwallstreet.com,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of, and basis for, the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

Many of NASDAQ's rules are based on rules of FINRA (formerly the National Association of Securities Dealers (''NASD'')). Beginning in 2008, FINRA embarked on an extended process of moving rules formerly designated as ''NASD Rules'' into a consolidated FINRA rulebook. In most cases, FINRA has renumbered these rules, and in some cases has substantively amended them. Accordingly, NASDAQ also has initiated a process of modifying its rulebook to ensure that NASDAQ rules corresponding to FINRA/NASD rules continue to mirror them as closely as practicable.

This proposed rule change concerns NASDAQ Rule 3020 entitled ''Fidelity Bonds,'' which follows and incorporates by reference former NASD Rule 3020.[3] FINRA recently amended its rules to adopt former NASD Rule 3020, relating to Fidelity Bonds, with certain changes, into the consolidated FINRA rulebook as FINRA Rule 4360.[4] NASDAQ Rule 3020 provides that ''[a] member designated to Nasdaq for oversight pursuant to SEC Rule 17d–1 shall comply with NASD Rule 3020 as if such Rule were part of Nasdaq's Rules.'' The Exchange proposes to amend this text to reference new FINRA Rule 4360, which replaced NASD Rule 3020.

NASD Rule 3020(a) generally provides that each member required to join the Securities Investor Protection Corporation (''SIPC'') that has employees and that is not a member in good standing of one of the enumerated national securities exchanges must maintain fidelity bond coverage. FINRA Rule 4360 requires each member that is required to join SIPC to maintain blanket fidelity bond coverage with specified amounts of coverage based on the member's net capital requirement, with certain exceptions. NASD Rule 3020(a)(1) requires members to maintain a blanket fidelity bond in a form substantially similar to the standard form of Brokers Blanket Bond promulgated by the Surety Association of America. New FINRA Rule 4360 requires members to maintain fidelity bond coverage that provides for per loss coverage without an aggregate limit of liability. Also, pursuant to FINRA Rule 4360, a member's fidelity bond must provide against loss and have Insuring Agreements covering at least the following: Fidelity, on premises, in transit, forgery and alteration, securities and counterfeit currency. The rule change modified the descriptive headings for these Insuring Agreements, in part, from NASD Rule 3020(a)(1) and NYSE Rule 319(d) to align them with the headings in the current bond forms available to broker-dealers. FINRA Rule 4360 also eliminates the specific coverage provisions in NASD Rule

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] The purpose of the fidelity bond is to protect a member against certain types of losses, including, but not limited to, those caused by the malfeasance of its officers and employees, and the effect of such losses on the member's capital.

[4] *See* Securities Exchange Act Release No. 63961 (February 24, 2011), 76 FR 11542 (March 2, 2011) (SR–FINRA–2010–059) (a rule change to adopt a rule of the National Association of Securities Dealers, Inc. (''NASD'') as part of the consolidation of the FINRA rulebook). This new rule took into account Incorporated NYSE Rule 319 (Fidelity Bonds) and its Interpretation.

3020(a)(4) and (a)(5), and NYSE Rule 319(d)(ii)(B) and (C), and (e)(ii)(B) and (C), that permit less than 100 percent of coverage for certain Insuring Agreements (*i.e.,* fraudulent trading and securities forgery) to require that coverage for all Insuring Agreements be equal to 100 percent of the firm's minimum required bond coverage.[5]

Further, FINRA Rule 4360 requires that a member's fidelity bond include a cancellation rider providing that the insurer will use its best efforts to promptly notify FINRA in the event the bond is cancelled, terminated or ''substantially modified.'' Also, the rule change adopted the definition of ''substantially modified'' in NYSE Rule 319 and would incorporate NYSE Rule 319.12's standard that a firm must immediately advise FINRA in writing if its fidelity bond is cancelled, terminated or substantially modified.[6] FINRA added supplementary material to FINRA Rule 4360 requiring members that do not qualify for a bond with per loss coverage without an aggregate limit of liability to secure alternative coverage. Specifically, a member that does not qualify for blanket fidelity bond coverage as required by FINRA Rule 4360(a)(3) is required to maintain substantially similar fidelity bond coverage in compliance with all other provisions of the rule, provided that the member maintains written correspondence from two insurance providers stating that the member does not qualify for the coverage required by FINRA Rule 4360(a)(3).

FINRA Rule 4360 requires each member to maintain, at a minimum, fidelity bond coverage for any person associated with the member, except directors or trustees of a member who are not performing acts within the scope of the usual duties of an officer or employee. As further detailed below, the rule change eliminated the exemption in NASD Rule 3020 for sole stockholders and sole proprietors. The rule change also increased the minimum required fidelity bond coverage for members, while continuing to base the coverage on a member's net capital requirement. To that end, FINRA Rule 4360 required a member with a net capital requirement that is less than $250,000 to maintain minimum coverage of the greater of 120 percent of the firm's required net capital under Exchange Act Rule 15c3–1 or $100,000. The increase to $100,000 modifies the present minimum requirement of $25,000.

Under the new FINRA Rule 4360, members with a net capital requirement of at least $250,000 must use a table in the rule to determine their minimum fidelity bond coverage requirement. The table is a modified version of the tables in NASD Rule 3020(a)(3) and NYSE Rule 319(e)(i). The identical NASD and NYSE requirements for members that have a minimum net capital requirement that exceeds $1 million are retained in the new Rule; however, the rule adopts the higher requirements in NYSE Rule 319(e)(i) for a member with a net capital requirement of at least $250,000, but less than $1 million. Under the new rule, the entire amount of a member's minimum required coverage must be available for covered losses and may not be eroded by the costs an insurer may incur if it chooses to defend a claim. Specifically, any defense costs for covered losses must be in addition to a member's minimum coverage requirements. A member may include defense costs as part of its fidelity bond coverage, but only to the extent that it does not reduce a member's minimum required coverage under the rule.

Under prior NASD Rule 3020(b), a deductible provision may be included in a member's bond of up to $5,000 or 10% of the member's minimum insurance requirement, whichever is greater. If a member desires to maintain coverage in excess of the minimum insurance requirement, then a deductible provision may be included in the bond of up to $5,000 or 10% of the amount of blanket coverage provided in the bond purchased, whichever is greater. The excess of any such deductible amount over the maximum permissible deductible amount based on the member's minimum required coverage must be deducted from the member's net worth in the calculation of the member's net capital for purposes of Exchange Act Rule 15c3–1. Where the member is a subsidiary of another member, the excess may be deducted from the parent's rather than the subsidiary's net worth, but only if the parent guarantees the subsidiary's net capital in writing.[7]

FINRA Rule 4360 provides for an allowable deductible amount of up to 25% of the fidelity bond coverage purchased by a member. Any deductible amount elected by the firm that is greater than 10% of the coverage purchased by the member[8] would be deducted from the member's net worth in the calculation of its net capital for purposes of Exchange Act Rule 15c3–1.[9] Like the NASD and NYSE rules, if the member is a subsidiary of another FINRA member, this amount may be deducted from the parent's rather than the subsidiary's net worth, but only if the parent guarantees the subsidiary's net capital in writing.

Consistent with NASD Rule 3020(c) and NYSE Rule 319.10, FINRA Rule 4360 requires a member (including a firm that signs a multi-year insurance policy), annually as of the yearly anniversary date of the issuance of the fidelity bond, to review the adequacy of its fidelity bond coverage and make any required adjustments to its coverage, as set forth in the rule. Under FINRA Rule 4360(d), a member's highest net capital requirement during the preceding 12-month period, based on the applicable method of computing net capital (dollar minimum, aggregate indebtedness or alternative standard), is used as the basis for determining the member's minimum required fidelity bond coverage for the succeeding 12-month period. The ''preceding 12-month period'' includes the 12-month period that ends 60 days before the yearly anniversary date of a member's fidelity bond. This would give a firm time to determine its required fidelity bond coverage by the anniversary date of the bond.

Further, FINRA Rule 4360 allows a member that has only been in business for one year and elected the aggregate indebtedness ratio for calculating its net capital requirement to use, solely for the purpose of determining the adequacy of its fidelity bond coverage for its second year, the 15 to 1 ratio of aggregate indebtedness to net capital in lieu of the 8 to 1 ratio (required for broker-dealers

[5] Members may elect to carry additional, optional Insuring Agreements not required by FINRA Rule 4360 for an amount less than 100 percent of the minimum required bond coverage.

[6] NYSE Rule 319 defines the term ''substantially modified'' as any change in the type or amount of fidelity bonding coverage, or in the exclusions to which the bond is subject, or any other change in the bond such that it no longer complies with the requirements of the rule.

[7] Under NYSE Rule 319(b), each member organization may self-insure to the extent of $10,000 or 10% of its minimum insurance requirement as fixed by the NYSE, whichever is greater, for each type of coverage required by the rule. Self-insurance in amounts exceeding the above maximum may be permitted by the NYSE provided the member or member organization certifies to the satisfaction of the NYSE that it is unable to obtain greater bonding coverage, and agrees to reduce its self-insurance so as to comply with the above stated limits as soon as possible, and appropriate charges to capital are made pursuant to Exchange Act Rule 15c3–1. This provision also contains identical language to the NASD rule regarding net worth deductions for subsidiaries.

[8] FINRA notes that a member may elect, subject to availability, a deductible of less than 10 percent of the coverage purchased.

[9] NASD Rule 3020 bases the deduction from net worth for an excess deductible on a firm's minimum required coverage, while FINRA Rule 4360 would base such deduction from net worth on coverage *purchased* by the member.

in their first year of business) to calculate its net capital requirement. Notwithstanding the above, such member would not be permitted to carry less minimum fidelity bond coverage in its second year than it carried in its first year.

Based in part on NASD Rule 3020(a), FINRA Rule 4360 exempts from the fidelity bond requirements members in good standing with a national securities exchange that maintain a fidelity bond subject to the requirements of such exchange that are equal to or greater than the requirements set forth in Rule 4360. Additionally, consistent with NYSE Rule Interpretation 319/01, FINRA Rule 4360 continues to exempt from the fidelity bond requirements any firm that acts solely as a Designated Market Maker (''DMM''),[10] floor broker or registered floor trader and does not conduct business with the public. FINRA Rule 4360 does not maintain the exemption in NASD Rule 3020(e) for a one-person firm.[11] Historically, a sole proprietor or sole stockholder member was excluded from the fidelity bond requirements based upon the assumption that such firms were one-person shops and, therefore, could not obtain coverage for their own acts. FINRA has determined that sole proprietors and sole stockholder firms can and often do acquire fidelity bond coverage, even though it is currently not required, since all claims (irrespective of firm size) are likely to be paid or denied on a facts-and-circumstances basis. Also, certain coverage areas of the fidelity bond benefit a one-person shop (*e.g.,* those covering customer property lost in transit).

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act [12] in general, and furthers the objectives of Section 6(b)(5) of the Act [13] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest, by updating and clarifying the requirements governing fidelity bonds. The Exchange believes that the proposed requirements of Rule 4360, including, but not limited to, requiring each member that is required to join SIPC to maintain blanket fidelity bond coverage, increasing the minimum requirement fidelity bond coverage and maintaining a fidelity bond that provides for per loss coverage without an aggregate limit of liability promotes investor protection by protecting firms from unforeseen losses. The proposed amendments will conform NASDAQ Rule 3020 to recent changes made to a corresponding FINRA rule, to promote application of consistent regulatory standards.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days after the date of the filing, or such shorter time as the Commission may designate, it has become effective pursuant to 19(b)(3)(A) of the Act [14] and Rule 19b–4(f)(6) [15] thereunder.

The Exchange has requested that the Commission waive the 30-day operative delay. The Commission believes that waiver of the operative delay is consistent with the protection of investors and the public interest because the proposed rule change presents no novel issues, and NASDAQ members are currently subject to FINRA Rule 4360. Therefore, the Commission designates the proposal operative upon filing.[16]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an email to *rule-comments@sec.gov.* Please include File Number SR–NASDAQ–2012–021 on the subject line.

Paper Comments

• Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NASDAQ–2012–021. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*).

Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC 20549, on official business days between the hours of 10

[10] *See* [sic] Exchange Act Release No. 58845 (Oct. 24, 2008), 73 FR 64379 (Oct. 29, 2008) (Order Approving File No. SR–NYSE–2008–46). In this rule filing, the role of the specialist was altered in certain respects and the term ''specialist'' was replaced with the term ''Designated Market Maker.''

[11] A one-person member (that is, a firm owned by a sole proprietor or stockholder that has no other associated persons, registered or unregistered) has no ''employees'' for purposes of NASD Rule 3020, and therefore such a firm currently is not subject to the fidelity bonding requirements. Conversely, a firm owned by a sole proprietor or stockholder that has other associated persons has ''employees'' for purposes of NASD Rule 3020, and currently is, and will continue to be, subject to the fidelity bonding requirements.

[12] 15 U.S.C. 78f(b).

[13] 15 U.S.C. 78f(b)(5).

[14] 15 U.S.C. 78s(b)(3)(A).

[15] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[16] For purposes only of waiving the 30-day operative delay, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

a.m. and 3 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NASDAQ–2012–021 and should be submitted on or before March 8, 2012.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[17]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3612 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–66376; File No. SR–NYSEAmex–2012–05]

Self-Regulatory Organizations; NYSE Amex LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Amending an Existing Rebate Relating to Qualified Contingent Cross Orders That Are Entered and Executed Through the Exchange Systems

February 10, 2012.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on January 30, 2012, NYSE Amex LLC (the ''Exchange'' or ''NYSE Amex'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend an existing rebate relating to Qualified Contingent Cross (''QCC'') orders that are entered and executed through the Exchange systems. The text of the proposed rule change is available at the Exchange, the Commission's Public Reference Room, and *www.nyse.com.*

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposal is to increase a rebate for Floor Brokers who enter QCC orders that subsequently execute.[3] The Exchange intends to increase the existing rebate of $.03 per executed contract to $.07 per executed contract.[4]

The rebate is credited to the executing Floor Broker. The Exchange notes that the terms of a QCC order are negotiated and agreed to prior to being brought to an exchange for possible execution. In bringing a QCC order to the Exchange for execution, permit holders have two primary means of doing so. They can configure their systems to deliver the QCC order to the Exchange matching engines for validation and execution. Alternatively they can utilize the services of another ATP Holder acting as a Floor Broker. In turn, the Floor Broker who is in receipt of such an order can enter the order through an Exchange-provided system [5] to be delivered to the Exchange matching engine for validation and potential execution. The Exchange does not offer a front-end for order entry, unlike some of the competing exchanges.[6] The Exchange expects that the increased rebate offered to executing Floor Brokers will allow them to price their services at a level that will enable them to attract QCC order flow from participants who would otherwise utilize an existing front-end order entry mechanism offered by the Exchange's competitors or floor brokers on other exchanges, instead of incurring the cost in time and money to develop their own internal systems to be able to deliver QCC orders directly to the Exchange systems. To the extent that Floor Brokers are able to attract these QCC orders, they will gain important information that will allow them to solicit the parties to the QCC orders for participation in other trades, which will in turn benefit all other Exchange participants through the additional liquidity and price discovery that may occur as a result. The proposed change is also a competitive response to recent pricing changes at competing exchanges.[7] The proposed change will be operative on February 1, 2012.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the provisions of Section 6(b) [8] of the Securities Exchange Act of 1934 (the ''Act''), in general, and Section 6(b)(4) [9] of the Act, in particular, in that it is designed to provide for the equitable allocation of reasonable dues, fees, and other charges among its members and other persons using its facilities.

The Exchange believes the proposed increase from $.03 per contract to $.07 per contract rebate for Floor Brokers who enter QCC orders that execute is reasonable because it will allow Floor Brokers the opportunity to compete for QCC orders that would otherwise be

[17] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 65472 (October 3, 2011), 76 FR 62887 (October 11, 2011) (SR–NYSEAmex–2011–72). *See* also Securities Exchange Act Release No. 65047 (August 5, 2011), 76 FR 49812 (August 11, 2011) (SR–NYSEAmex–2011–56). The QCC permits an NYSE Amex ATP Holder to effect a qualified contingent trade (''QCT'') in a Regulation NMS stock and cross the options leg of the trade on the Exchange immediately upon entry and without order exposure if the order is for at least 1,000 contracts, is part of a QCT, is executed at a price at least equal to the national best bid or offer, as long as there are no Customer orders in the Exchange's Consolidated Book at the same price.

[4] The exclusion of Customer-to-Customer QCC trades from the Floor Broker rebate will remain. *See* Securities Act Release No. 65943 (December 13, 2011), 76 FR 78704 (December 19, 2011) (SR–NYSEAmex–2011–95).

[5] Floor Brokers are required by NYSE Amex Rule 955NY to have systematized orders prior to representing them in open outcry. Using the same Electronic Order Capture System, Floor Brokers will be able to enter QCC orders for validation by the Exchange matching engines and potential execution.

[6] The International Securities Exchange (''ISE'') offers PRECISE TRADE as a means for users to enter orders and Chicago Board Options Exchange has a similar front-end order entry system called PULSE. Such systems do not require users to develop their own internal front-end order entry systems and may provide savings to users in terms of development time and costs.

[7] *See* Securities Act Release No. 66169 (January 17, 2011) (SR–ISE–2012–01) (notice of filing and immediate effectiveness of a proposed rule change, including an increase in ISE rebate of up to $.10 per contract for qualifying executed QCC orders), and NASDAQ OMX PHLX fee schedule dated January 18, 2012, page 5 (describing a rebate of up to $.10 per contract for qualifying executed QCC Orders), available at *http://www.nasdaqtrader.com/content/marketregulation/membership/phlx/feesched.pdf.*

[8] 15 U.S.C. 78f(b).

[9] 15 U.S.C. 78f(b)(4).

entered into front-end order entry systems of competing exchanges or sent to floor brokers on exchanges that offer higher rebates.[10] The proposed rebate is comparable to or less than rebates offered on both the ISE and NASDAQ OMX PHLX in that it is being offered to Floor Brokers as an inducement that may allow them to competitively price their services offered to all participants.[11] To the extent that the rebate is successful in attracting additional order flow to the Exchange, all participants should benefit. As such the Exchange believes that the rebate is appropriate and reasonable.

The Exchange believes the proposal to increase the rebate from $.03 per contract to a $.07 per contract is equitable and not unfairly discriminatory because it would uniformly apply to all QCC orders entered by a Floor Broker for validation by the system and potential execution, excepting Customer-to-Customer QCC trades. The exclusion of Customer-to-Customer QCC trades from the Floor Broker rebate will remain.[12] Any participant will be able to engage a rebate-receiving Floor Broker in a discussion surrounding the appropriate level of fees that they may be charged for entrusting the entry of the QCC order to the Floor Broker into the Exchange systems for validation and execution. The additional order flow attracted by this increase in the rebate should benefit all participants. For this reason the Exchange feels the adoption of the proposed rebate increase is both equitable and not unfairly discriminatory.

For the reasons noted above, the Exchange believes that the proposed fees are fair, equitable and not unfairly discriminatory.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

[10] *See supra* note 6.

[11] *See supra* note 7.

[12] *See supra* note 4.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change is effective upon filing pursuant to Section 19(b)(3)(A)[13] of the Act and subparagraph (f)(2) of Rule 19b–4[14] thereunder, because it establishes a due, fee, or other charge imposed by the NYSE Amex.

At any time within 60 days of the filing of such proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an email to *rule-comments@sec.gov.* Please include File Number SR–NYSEAmex–2012–05 on the subject line.

Paper Comments

• Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEAmex–2012–05. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NW., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEAmex–2012–05 and should be submitted on or before March 8, 2012.

[13] 15 U.S.C. 78s(b)(3)(A).

[14] 17 CFR 240.19b–4(f)(2).

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[15]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2012–3608 Filed 2–15–12; 8:45 am]

BILLING CODE 8011–01–P

[15] 17 CFR 200.30–3(a)(12).

DEPARTMENT OF STATE

[Public Notice 7801]

30-Day Notice of Proposed Information Collection: DS–86, Statement of Non-Receipt of a Passport

ACTION: Notice of request for public comment and submission to OMB of proposed collection of information.

SUMMARY: The Department of State has submitted the following information collection request to the Office of Management and Budget (OMB) for approval in accordance with the Paperwork Reduction Act of 1995.

• *Title of Information Collection:* Statement of Non-Receipt of a Passport.

• *OMB Control Number:* 1405–0146.

• *Type of Request:* Revision of a Currently Approved Collection.

• *Originating Office:* Bureau of Consular Affairs, CA/PPT/PMO/PC.

• *Form Number:* DS–86.

• *Respondents:* Individuals who have not received the passport for which they originally applied.

• *Estimated Number of Respondents:* 12,755 per year.

• *Estimated Number of Responses:* 12,755 per year.

• *Average Hours per Response:* 5 min.

• *Total Estimated Burden:* 1,063 hours.

• *Frequency:* On Occasion.

• *Obligation to Respond:* Required to Obtain a Benefit.

DATES: Submit comments to the Office of Management and Budget (OMB) for up to 30 days from February 16, 2012.

ADDRESSES: Direct comments to the Department of State Desk Officer in the Office of Information and Regulatory Affairs at the Office of Management and Budget (OMB). You may submit comments by the following methods:

- *Email: oira_submission@omb.eop.gov.* You must include the DS form number, information collection title, and OMB control number in the subject line of your message.
- *Fax:* 202–395–5806. Attention: Desk Officer for Department of State.

FOR FURTHER INFORMATION CONTACT: You may obtain copies of the proposed information collection and supporting documents from Passport Services, Passport Forms Management and Officer, U.S. Department of State, Office of Program Management and Operational Support, 2201 C Street NW., Washington, DC 20520, who may be reached on 202–663–2457 or at *PPTFormsOfficer@state.gov.*

SUPPLEMENTARY INFORMATION: We are soliciting public comments to permit the Department to:

- Evaluate whether the proposed information collection is necessary to properly perform our functions.
- Evaluate the accuracy of our estimate of the burden of the proposed collection, including the validity of the methodology and assumptions used.
- Enhance the quality, utility, and clarity of the information to be collected.
- Minimize the reporting burden on those who are to respond.

Abstract of Proposed Collection

This Statement of Non-Receipt is used by the U.S. Department of State to collect information for the purpose of issuing a replacement passport to customers who have not received the passport for which they originally applied.

Methodology

Passport applicants who do not receive their passports are required to complete a Statement of Non-Receipt of a Passport, Form DS–86. Passport applicants can either download the form from the Internet or pick one up from an Acceptance Facility/Passport Agency. The form must be completed, signed, and then submitted to the Acceptance Facility/Passport Agency for passport re-issuance.

Dated: February 7, 2012.

Barry J. Conway,

Managing Director for Support Operations, Passport Services, Department of State.

[FR Doc. 2012–3696 Filed 2–15–12; 8:45 am]

BILLING CODE 4710–06–P

DEPARTMENT OF STATE

[Public Notice 7800]

Thirty-Day Notice of Proposed Information Collection: DS–71, Affidavit of Identifying Witness

ACTION: Notice of request for public comment and submission to OMB of proposed collection of information.

SUMMARY: The Department of State has submitted the following information collection request to the Office of Management and Budget (OMB) for approval in accordance with the Paperwork Reduction Act of 1995.

- *Title of Information Collection:* Affidavit of Identifying Witness.
- *OMB Control Number:* 1405–0088.
- *Type of Request:* Revision of a Currently Approved Collection.
- *Originating Office:* Bureau of Consular Affairs, CA/PPT/PMO/PC.
- *Form Number:* DS–71.
- *Respondents:* Individuals who are verifying identity of a passport applicant.
- *Estimated Number of Respondents:* 44,000 per year.
- *Estimated Number of Responses:* 44,000 per year.
- *Average Hours per Response:* 5 min.
- *Total Estimated Burden:* 3667 hours.
- *Frequency:* On Occasion.
- *Obligation to Respond:* Required to Obtain a Benefit.

DATES: Submit comments to the Office of Management and Budget (OMB) for up to 30 days from February 16, 2012.

ADDRESSES: Direct comments to the Department of State Desk Officer in the Office of Information and Regulatory Affairs at the Office of Management and Budget (OMB). You may submit comments by the following methods:

- *Email: oira_submission@omb.eop.gov.* You must include the DS form number, information collection title, and OMB control number in the subject line of your message.
- *Fax:* 202–395–5806. Attention: Desk Officer for Department of State.

FOR FURTHER INFORMATION CONTACT: You may obtain copies of the proposed information collection and supporting documents from Passport Services, Passport Forms Management and Officer, U.S. Department of State, Office of Program Management and Operational Support, 2201 C Street NW., Washington, DC 20520, who may be reached on 202–663–2457 or at *PPTFormsOfficer@state.gov.*

SUPPLEMENTARY INFORMATION: We are soliciting public comments to permit the Department to:

- Evaluate whether the proposed information collection is necessary to properly perform our functions.
- Evaluate the accuracy of our estimate of the burden of the proposed collection, including the validity of the methodology and assumptions used.
- Enhance the quality, utility, and clarity of the information to be collected.
- Minimize the reporting burden on those who are to respond,

Abstract of Proposed Collection

The Affidavit of Identifying Witness is submitted in conjunction with an application for a U.S. passport. It is used by Passport Services to collect information for the purpose of establishing the identity of the applicant. This application is completed by the identifying witness when the applicant is unable to establish his or her identity to the satisfaction of a person authorized to accept passport applications.

Methodology:

The Affidavit of Identifying Witness is submitted in conjunction with an application for a U.S. passport. Due to legislative mandates Form DS–0071 is only available at acceptance facilities and passport agencies. This form must be completed and signed in the presence of an authorized Passport Agent, Acceptance Agent, or Consular Officer.

Dated: February 7, 2012.

Barry J. Conway,

Managing Director for Support Operations, Passport Services, Department of State.

[FR Doc. 2012–3700 Filed 2–15–12; 8:45 am]

BILLING CODE 4710–06–P

DEPARTMENT OF STATE

[Public Notice 7799]

Determination With Respect to Foreign Governments' Efforts Regarding Trafficking in Persons—Burma

Pursuant to section 110 of Trafficking Victims Protection Act of 2000 (Division A, Pub. L. 106–386), as amended (the ''Act''), and the Presidential memorandum of delegation signed on February 3, 2012, I hereby determine, consistent with sections 110(d)(4) and 110(f) of the Act, that provision to the Government of Burma of all programs, projects, or activities of assistance described in sections 110(d)(1)(B) of the Act would promote the purposes of the Act or is otherwise in the national interest of the United States.

This determination shall be published in the **Federal Register**, and copies shall be transmitted to the appropriate committees in Congress.

Dated: February 6, 2012.

Hillary Rodham Clinton,

Secretary of State.

[FR Doc. 2012–3695 Filed 2–15–12; 8:45 am]

BILLING CODE 4710–02–P

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

Notice of Applications for Certificates of Public Convenience and Necessity and Foreign Air Carrier Permits Filed Under Subpart B (Formerly Subpart Q) During the Week Ending February 4, 2012

The following Applications for Certificates of Public Convenience and Necessity and Foreign Air Carrier Permits were filed under Subpart B (formerly Subpart Q) of the Department of Transportation's Procedural Regulations (See 14 CFR 301.201 et seq.). The due date for Answers, Conforming Applications, or Motions to Modify Scope are set forth below for each application. Following the Answer period DOT may process the application by expedited procedures. Such procedures may consist of the adoption of a show-cause order, a tentative order, or in appropriate cases a final order without further proceedings.

Docket Number: DOT–OST–2012–0016.

Date Filed: January 30, 2012.

Due Date for Answers, Conforming Applications, or Motion to Modify Scope: February 21, 2012.

Description: Application of Helicopteros Dominicanos, S.A. requesting a foreign air carrier permit and exemption authority to engage in (i) charter foreign air transportation of persons and property between points in the Dominican Republic and points in the United States and beyond, with or without stopovers, and (ii) Fifth Freedom charter service pursuant to the prior approval requirements.

Docket Number: DOT–OST–2012–0017.

Date Filed: January 30, 2012.

Due Date for Answers, Conforming Applications, or Motion to Modify Scope: February 21, 2012.

Description: Application of Polskie Linie Lotnicze LOT S.A. (''LOT'') requesting an exemption and amended foreign air carrier permit authorizing LOT to engage in foreign air transportation to the full extent permitted by the United States-European Union Air Transport Agreement. More specifically, LOT requests authority to engage in: (a) Foreign scheduled and charter air transportation of persons, property, and mail from any point or points behind any Member State of the European Union, via any point or points in any Member State and via intermediate points to any point or points in the United States and beyond; (b) foreign scheduled and charter air transportation of persons, property, and mail between any point or points in the United States and any point or points in any member of the European Common Aviation Area; (c) other charters pursuant to the prior approval requirements; and (d) transportation authorized by any additional route rights made available to European Union carriers in the future.

Renee V. Wright,

Program Manager, Docket Operations, Federal Register Liaison.

[FR Doc. 2012–3493 Filed 2–15–12; 8:45 am]

BILLING CODE 4910–9X–P

DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

[Docket Number FRA–2012–0012]

Notice of Application for Approval of Discontinuance or Modification of a Railroad Signal System

In accordance with Part 235 of Title 49 of the Code of Federal Regulations (CFR) and 49 U.S.C. 20502(a), this document provides the public notice that by a document dated January 18, 2012, the Union Pacific Railroad (UP) has petitioned the Federal Railroad Administration (FRA) seeking approval for the discontinuance or modification of a signal system. FRA assigned the petition Docket Number FRA–2012–0012.

UP seeks approval of the proposed discontinuance of the automatic block signal (ABS) system between Control Point (CP) Troost and Neff Yard on UP's KC Metro Subdivision, at approximately Milepost 281. UP's plans call for the discontinuance of ABS Signals Numbers 2805L, 2805R, 2806L, and 2806R, on Track 112 and Main 2; as well as a switch circuit controller on a hand-operated switch on Track 112.

The reason given is that the ABS system is not needed for efficient and safe operation of trains in this area.

A copy of the petition, as well as any written communications concerning the petition, is available for review online at *www.regulations.gov* and in person at the U.S. Department of Transportation's (DOT) Docket Operations Facility, 1200 New Jersey Avenue SE., W12–140, Washington, DC 20590. The Docket Operations Facility is open from 9 a.m. to 5 p.m., Monday through Friday, except Federal holidays.

Interested parties are invited to participate in these proceedings by submitting written views, data, or comments. FRA does not anticipate scheduling a public hearing in connection with these proceedings since the facts do not appear to warrant a hearing. If any interested party desires an opportunity for oral comment, they should notify FRA, in writing, before the end of the comment period and specify the basis for their request.

All communications concerning these proceedings should identify the appropriate docket number and may be submitted by any of the following methods:

- *Web site: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* Docket Operations Facility, U.S. Department of Transportation, 1200 New Jersey Avenue SE., W12–140, Washington, DC 20590.
- *Hand Delivery:* 1200 New Jersey Avenue SE., Room W12–140, Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Communications received by April 2, 2012 will be considered by FRA before final action is taken. Comments received after that date will be considered as far as practicable.

Anyone is able to search the electronic form of any written communications and comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (Volume 65, Number 70; Pages 19477–78).

Issued in Washington, DC, on February 9, 2012.

Ron Hynes,

Acting Deputy Associate Administrator for Regulatory and Legislative Operations.

[FR Doc. 2012–3679 Filed 2–15–12; 8:45 am]

BILLING CODE 4910–06–P

DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

[Docket Number FRA–2012–0002]

Petition for Waiver of Compliance

In accordance with Part 211 of Title 49 of the Code of Federal Regulations (CFR), this document provides the public notice that by a document dated December 19, 2011, Durango & Silverton Narrow Gauge Railroad (DSNG) has petitioned the Federal Railroad Administration (FRA) for a waiver of compliance from certain provisions of the Federal railroad safety regulations contained at 49 CFR Part 230, Steam Locomotive Inspection and Maintenance Standards. FRA assigned the petition Docket Number FRA–2012–0002.

DSNG is a tourist railroad that operates between Durango and Silverton, CO. The railroad maintains six narrow gauge (36-inch) steam locomotives; four 1925 Baldwin 2–8–2 locomotives and two 1923 Alco 2–8–2 locomotives. All of these locomotives have received previous 1,472 service-day inspections (SDI) in accordance with 49 CFR 230.17 and will soon receive their second 1,472 SDI due to an accumulation of service days rather than an expiration of the 15 years permitted by 49 CFR 230.17.

Locomotive No. 480, a 1925 Baldwin 2–8–2, has accumulated 1,307 days of service. This locomotive is currently removed from service due to a crack found on the knuckle of the rear flue sheet necessitating repair or replacement. Replacement was chosen due to the age of the existing flue sheet and the added safety of replacement versus repairing the crack in place. Replacement requires that all of the boiler flues will have to be removed to affect the repair. The flues will be removed 165 service days earlier than required for the 1,472 SDI. While the flues are removed, DSNG will clean and inspect the boiler interior as required by 49 CFR 230.31 and 230.32(b)(2), and the applicable portions of 49 CFR 230.32(a).

DSNG requests relief from 49 CFR 230.31(a) with respect to timeframe, and 49 CFR 230.32(b)(3) with respect to boiler exterior. DSNG desires to perform the interior portion of the 1,472 SDI; return the locomotive back into service for the remainder of the 2012 operating season; and complete the exterior portion of the 1,472 SDI at or before the expiration of its present 1,472 service-day cycle. DSNG states that granting of relief will allow extensive monetary savings, as removing and replacing the flues twice within 12 months would be burdensome and costly with a negligible effect on safety. The request is for permission to perform the interior boiler inspection earlier than required. The use of service time for the next 1,472 SDI will start with the first firing of the boiler after returning to service, not at the completion of the exterior inspection.

A copy of the petition, as well as any written communications concerning the petition, is available for review online at *http://www.regulations.gov* and in person at the U.S. Department of Transportation's (DOT) Docket Operations Facility, 1200 New Jersey Avenue SE., W12–140, Washington, DC 20590. The Docket Operations Facility is open from 9 a.m. to 5 p.m., Monday through Friday, except Federal holidays.

Interested parties are invited to participate in these proceedings by submitting written views, data, or comments. FRA does not anticipate scheduling a public hearing in connection with these proceedings since the facts do not appear to warrant a hearing. If any interested party desires an opportunity for oral comment, they should notify FRA, in writing, before the end of the comment period and specify the basis for their request.

All communications concerning these proceedings should identify the appropriate docket number and may be submitted by any of the following methods:

- *Web site: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* Docket Operations Facility, U.S. Department of Transportation, 1200 New Jersey Avenue SE., W12–140, Washington, DC 20590.
- *Hand Delivery:* 1200 New Jersey Avenue SE., Room W12–140, Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Communications received by April 2, 2012 will be considered by FRA before final action is taken. Comments received after that date will be considered as far as practicable.

Anyone is able to search the electronic form of any written communications and comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (Volume 65, Number 70; Pages 19477–78), or online at *http://www.dot.gov/privacy.html.*

Issued in Washington, DC, on February 13, 2012.

Ron Hynes,

Acting Deputy Associate Administrator for Regulatory and Legislative Operations.

[FR Doc. 2012–3683 Filed 2–15–12; 8:45 am]

BILLING CODE 4910–06–P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

[Docket No. NHTSA–2012–0021]

National Emergency Medical Services Advisory Council (NEMSAC); Notice of Federal Advisory Committee Meeting

AGENCY: National Highway Traffic Safety Administration (NHTSA), U.S. Department of Transportation (DOT).

ACTION: Meeting Notice—National Emergency Medical Services Advisory Council.

SUMMARY: The NHTSA announces a meeting of NEMSAC to be held in the Metropolitan Washington, DC area. This notice announces the date, time, and location of the meeting, which will be open to the public. This meeting will include a special roundtable event, hosted by the NEMSAC, regarding the EMS Education Agenda for the Future. The purpose of NEMSAC is to provide a nationally recognized council of emergency medical services (EMS) representatives and consumers to provide advice and recommendations regarding EMS to DOT's National Highway Traffic Safety Administration.

DATES: The NEMSAC meeting will take place over two and a half days and be held on Wednesday March 28, 2012, from 9 a.m. to 5 p.m. EST, Thursday March 29, 2012, from 1 p.m. to 5 p.m. EST, and on Friday March 30, 2012, from 8 a.m. to 12 p.m. EST. NEMSAC committees will meet from 8 a.m. to 12 p.m. on March 29, 2012. Public comment periods will be scheduled throughout the day of March 28, 2012, as well as from 3:30 p.m. to 4:30 p.m. EST on March 29, 2012.

ADDRESSES: The meeting will be held on the 8th floor of the FHI 360 Conference Center at 1825 Connecticut Avenue NW., Washington, DC 20009.

FOR FURTHER INFORMATION CONTACT: Drew Dawson, Director, U.S. Department of Transportation, Office of Emergency Medical Services, 1200 New Jersey Avenue SE., NTI–140, Washington, DC 20590, telephone number (202) 366–9966; email *Drew.Dawson@dot.gov.*

SUPPLEMENTARY INFORMATION: Notice of this meeting is given under the Federal Advisory Committee Act, Public Law 92–463, as amended (5 U.S.C. App.). NEMSAC will meet on March 28–30, 2012, at the FHI 360 Conference Center at 1825 Connecticut Avenue NW., Washington, DC 20009. This meeting will include a special roundtable event, hosted by the NEMSAC, regarding the EMS Education Agenda for the Future. The purpose of the March 28, 2012, roundtable is to provide NEMSAC with stakeholder input about the EMS Education Agenda for the Future: A Systems Approach including a briefing on the Agenda's history and lessons learned from its implementation throughout the United States. This stakeholder input will help NEMSAC in making recommendations to the Department of Transportation and the Federal Interagency Committee on EMS regarding: The Agenda's future and a process for revising/updating the Agenda as deemed necessary and appropriate.

Agenda of National EMS Advisory Council Meeting, March 28–30, 2012

The tentative agenda includes the following:

Wednesday, March 28, 2012

(1) Opening Remarks
(2) History and Overview of the EMS Education Agenda for the Future
(3) Panel Discussion #1—Successes and Challenges in Implementing the Current Agenda
(4) Panel Discussion #2—Opportunities and Challenges in Revising the Agenda
(5) Panel Discussion #3—The Process To Revise the Agenda
(6) Next Steps

Thursday, March 29, 2012

(1) Opening Remarks
(2) Review and Approval of Minutes of Last Meeting
(3) Update From NHTSA Office of EMS
(4) Federal Partner Update
(5) Presentations From NEMSAC Committees
(6) Public Comment Period

Friday, March 30, 2012

(1) Deliberations of Committee Documents
(2) Discussion of New and Emerging Issues
(3) Unfinished Business/Continued Discussion From Previous Day
(4) Next Steps and Adjourn

Public comment periods will be scheduled throughout the day of March 28, 2012, as well as from 3:30 p.m. to 4:30 p.m. EST on March 29, 2012. Written comments or requests to make oral presentations must be received by March 21, 2012, by emailing *nemsac@dot.gov*. In order to allow as many people as possible to speak, speakers are requested to limit their remarks to 5 minutes.

Public Attendance: This meeting will be open to the public. There will not be a teleconference option for this meeting. Individuals wishing to attend must register online at *www.regonline.com/NEMSAC* no later than March 26, 2012.

Minutes of the NEMSAC Meeting will be available to the public online through *www.EMS.gov.*

Issued on: February 13, 2012.

Jeffrey P. Michael,

Associate Administrator for Research and Program Development.

[FR Doc. 2012–3624 Filed 2–15–12; 8:45 am]

BILLING CODE 4910–59–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

Office of Hazardous Materials Safety; Actions on Special Permit Applications

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice of actions on Special Permit Applications.

SUMMARY: In accordance with the procedures governing the application for, and the processing of, special permits from the Department of Transportation's Hazardous Material Regulations (49 CFR Part 107, Subpart B), notice is hereby given of the actions on special permits applications in (November to January 2012). The mode of transportation involved are identified by a number in the ''Nature of Application'' portion of the table below as follows: 1—Motor vehicle, 2—Rail freight, 3—Cargo vessel, 4—Cargo aircraft only, 5—Passenger-carrying aircraft. Application numbers prefixed by the letters EE represent applications for Emergency Special Permits. It should be noted that some of the sections cited were those in effect at the time certain special permits were issued.

Issued in Washington, DC, on February 02, 2012.

Donald Burger,

Chief, Special Permits and Approvals Branch.

S.P. No.	Applicant	Regulation(s)	Nature of special permit thereof
		MODIFICATION SPECIAL PERMIT GRANTED	
14447–M	SNF Holding Company Riceboro, GA.	49 CFR 177.834	To modify the special permit to authorize the addition of Class 3, 8 and Division 6.1 hazardous materials.
14763–M	Weatherford International Forth Worth, TX.	49 CFR 173.302a and 173.301(f)	To modify the special permit to change the minimum elongation from 12% to 10%.
12629–M	TEA Technologies, Inc. Amarillo, TX.	49 CFR 173.34(e)	To modify the special permit to add the retesting of DOT 107A cylinder (tubes) by means of acoustic emission (AE) and ultrasonic examination (UE) in lieu of hydrostatic testing.
14584–M	WavesinSolids LLC State College, PA.	49 CFR 173.302 and 180.209	To modify the special permit to authorize additional cylinders and to allow cylinders to be charged to 110 percent of the usual settled filled pressure or 110 percent of the stamped service pressure (whichever is greater) and to extend the retest period from 5 years to 10.
9758–M	Coleman Company, Inc. The Wichita, KS.	49 CFR 173.304(d)(3)(ii); 178.33	To modify the special permit to authorize the transportation in commerce of an additional Division 2.1 material.
14921–M	ERA Helicopters LLC Lake Charles, LA.	49 CFR 173.302(f)	To modify the special permit issued on an emergency basis to a permanent special permit.

S.P. No.	Applicant	Regulation(s)	Nature of special permit thereof
12247–M	Weldship Corporation Bethlehem, PA.	49 CFR 172.301, 173.302a(b)(2), (b)(3) and (b)(4); 180.205(c) and (g) and 180.209(a).	To modify the special permit to authorize ultrasonic testing of DOT–SP 9001, 9370, 9421, 9706, 9791, 9909, 10047, 10869, and 11692 cylinders.
14743–M	TIER Environmental Services, Inc. (Former Grantee TIER DE, Inc.) Gap, PA.	49 CFR 173.24b and 173.244	To modify the special permit to authorize the one-time, one-way transportation in commerce of an additional non-DOT specification metal tank containing approximately 1320 lbs. of sodium by motor vehicle.
11281–M	E.I. du Pont de Nemours & Company Wilmington, DE.	49 CFR 172.101, Column 7, Special Provisions B14, T38.	To modify the special permit to authorize the use of an additional UN portable tank specification.
15132–M	National Aeronautics and Space Administration (NASA) Washington, DC.	49 CFR 173.301 and 178.53	To modify the special permit to authorize the transportation in commerce of certain Division 2.1 and 2.2 gases in alterative packaging when transported by motor vehicle.
10597–M	Thermo King Corporation Minneapolis, MN.	49 CFR 177.834(1)(2)(i)	To modify the special permit to authorize a new series of heaters containing Class 3 liquids and/or Division 2.1 gases.
13601–M	DS Containers, Inc. Batavia, IL.	49 CFR 173.306(b)(1)	To modify the special permit to authorize an alternative pressure relief device.
14509–M	Pacific Consolidated Industries, LLC Riverside, CA.	49 CFR 173.302(a)(1), 173.304a(a)(1), 175.3.	To modify the special permit to authorize the transportation of cylinders containing oxidizing gases without a rigid outer packaging capable of passing the Flame Penetration and Resistance Test and the Thermal Resistance Test.
14728–M	International Isotopes Inc. Idaho Falls, ID.	49 CFR 173.416(c)	To modify the special permit to authorize an increase in the number of times the packaging can be used.

NEW SPECIAL PERMIT GRANTED

14839–N	Matheson Tri-Gas,Inc. Basking Ridge, NJ.	49 CFR 180.209	To authorize the transportation in commerce of certain DOT Specification 3A and 3AA cylinders containing Division 2.2 gases that have been tested every 15 years instead of every 10 years. (modes 1, 2, 3, 4, 5)
15257–N	GFS Chemicals Columbus, OH.	49 CFR 173.242(d) and 173.243(d)	To authorize the transportation of perchloric acid, a short distance from one facility to another, in intermediate bulk containers not otherwise authorized. (mode 1)
15274–N	Coastal Helicopters Juneau, AK.	49 CFR 172.101 Column (9B)	To authorize the transportation in commerce certain materials which are forbidden for transportation by air for exceed quantity limitations, to be transported by cargo aircraft within the State of Alaska when other means of transportation are impracticable or not available. (mode 4)
15384–N	TEA Technologies, Inc. Amarillo, TX.	49 CFR 180.509	To authorize an alternative method of retest for DOT Specification 107A cylinders for use in transporting liquified or nonliquefied compressed gases, or mixtures. (modes 1, 2, 3)
15373–N	Flinn Scientific Inc. Batavia, IL.	49 CFR 173.13(c)(2)	To authorize the manufacture, mark, sale and use of the specially designed combination packagings described herein for transportation in commerce of the materials listed in paragraph 6 without hazard labels or placards, with quantity limits not exceeding 25 grams. (mode 1)
15386–N	MAC, LLC Bay Saint Louis, MS.	49 CFR 173.56	To authorize the one-time, one-way transportation in commerce of two (2) 5-gallon buckets containing wetted waste primers and three (3) 5-gallon buckets containing wetted waste propellant by a contract carrier for disposal without an EX approval. (mode 1)
15404–N	Proserv UK Ltd. Aberdeen, AB12.	49 CFR 173.201, 173.302, 173.304, 3BT 178.35(e) and 178.36.	To authorize the manufacture, marking, sale and use of a non-DOT specification seamless titanium pressurized sample cylinder. (modes 1, 2, 3, 4)
15425–N	National Aeronautics & Space Administration (NASA) Washington, DC.	49 CFR 177.848	To authorize the transportation in commerce of certain hydrazine fuels on the same motor vehicle without regard to segregation requirements. (mode 1)
15427–N	The Proctor & Gamble Company LeGrange, GA.	49 CFR 173.306(a)(3)(v)	To authorize the transportation in commerce of certain aerosols containing a Division 2.2 compressed gas in certain non-refillable aerosol containers which are not subject to the hot water bath test. (modes 1, 2, 3, 4, 5, 6)
15428–N	Space Exploration Technologies Corp. Hawthorne, CA.	49 CFR Part 172 and 173	To authorize the transportation in commerce of certain hazardous material as part of the Dragon space capsule without requiring shipping papers, marking and labeling. (mode 1)

S.P. No.	Applicant	Regulation(s)	Nature of special permit thereof
15461–N	Kidde Products High Bentham, Yo.	49 CFR 171.23	To authorize the transportation in commerce of non-DOT specification cylinders containing a Division 2.2 compressed gas. (modes 1, 2, 3)
15470–N	Wilson Construction Company Canby, OR.	49 CFR 172.101 Column (9B), 172.204(c)(3), 173.27(b)(2), 175.30(a)(1), and 172.200.	To authorize the transportation in commerce of certain hazardous materials by cargo aircraft including by external load in remote areas of the U.S. without being subject to hazard communication requirements and quantity limitations where no other means of transportation is available. (mode 4)
15468–N	Prism Helicopters Inc. Wasilla, AK.	49 CFR 172.101 Column (9B)	To authorize the transportation in commerce of certain Class 1 explosive materials which are forbidden for transportation by air, to be transported by cargo aircraft within the State of Alaska when other means of transportation are impracticable or not available. (mode 4)
15471–N	National Aeronautics & Space Administration (NASA) Washington, DC.	49 CFR 173.172	To authorize the transportation in commerce of a Space Shuttle Orbiter Auxiliary Power Unit subsystem fuel propellant tank containing the residue of Hydrazine, anhydrous which does not meet the requirements of 49 CFR 173.172. (mode 1)
15473–N	Eagle Helicopters Inc. dba Kachina Aviation Nampa, ID.	49 CFR 172.101 Column (9B), 172.204(c)(3), 173.27(b)(2), 175.30(a)(1), and 172.200.	To authorize the transportation in commerce of certain hazardous materials by cargo aircraft including by external load in remote areas of the U.S. without being subject to hazard communication requirements and quantity limitations where no other means of transportation is available. (mode 4)
15443–N	Iliamna Air Guides, DBA Soloy Helicopters, LLC Wasilla, AK.	49 CFR 172.101 Column (9B), 172.204(c)(3), 173.27(b)(2), 175.30(a)(1), 172.200, 172.300 and 172.400.	To authorize the transportation in commerce of certain Class 1 hazardous materials by cargo aircraft including by external load in remote areas of the U.S. without being subject to hazard communication requirements and quantity limitations where no other means of transportation is available. (mode 3)
15466–N	The Boeing Company/Boeing Commerical Airplanes Seattle, WA.	49 CFR 173.309 in that the cylinders covered under this special permit are not authorized as fire extinguishers, except as specified herein, and § 172.301(c) in that marking each cylinder with the special permit number is waived.	To authorize the transportation in commerce of certain non-DOT specification and DOT–4DA and 4DS specification cylinders, used as fire suppression systems in aircraft to be shipped, as fire extinguishers. (modes 1, 2, 3, 4, 5)
15479–N	Korean Air Lines Co. Ltd. (KAL) Arlington, VA.	49 CFR 172.101 Column (9B)	To authorize the one-time transportation in commerce of certain explosives that are forbidden for transportation by cargo only aircraft. (mode 4)
15493–N	Carleton Technologies dba Cobham Mission Systems Orchard Park, NY.	49 CFR 173.302a	To authorize the manufacture, marking, sale and use of a nonrefillable non-DOT specification cylinder similar to a DOT specification 39 cylinder for use in transporting Division 2.2 non-flammable compressed gas. (modes 1, 2, 4, 5)
15476–N	Swanson Group Aviation, LLC Grants Pass, OR.	49 CFR 172.101 Column (9B), 172.204(c)(3), 173.27(b)(2), 175.30(a)(1), and 172.200.	To authorize the transportation in commerce of certain hazardous materials by external load on cargo aircraft in remote areas of the U.S. without being subject to hazard communication requirements and quantity limitations where no other means of transportation is available. (mode 4)

EMERGENCY SPECIAL PERMIT GRANTED

S.P. No.	Applicant	Regulation(s)	Nature of special permit thereof
11077–M	U.S. Department of Defense Scott AFB, IL.	49 CFR 173.226(b); 173.227(b)	To modify the special permit by removing one Division 6.1 hazardous materials and adding an additional Division 6.1 hazardous material. (mode 1)
15326–M	Chemtura Corporation Middlebury, CT.	49 CFR 178.337–8(a)(3)	To modify the special permit to extend the expiration date three months to allow time to modify the special permit from emergency to permanent. (mode 1)
15243–N	Katmai Air, LLC Anchorage, AK.	49 CFR 175.310(c)	Authorizes the carriage of gasoline in non-DOT specification polyethylene containers overpacked in plywood boxes in small, passenger-carrying aircraft within the State of Alaska to meet the needs of a passenger. (modes 4, 5)
15448–N	U.S. Department of Defense Scott AFB, IL.	49 CFR 172.320, 173.51, 173.56, 173.57 and 173.58.	To authorize the transportation in commerce of certain Class 1 materials under an Interim Hazard Classification. (modes 1, 2, 3, 4, 5)

S.P. No.	Applicant	Regulation(s)	Nature of special permit thereof
15505–N	Boasso America Corp. Chalmette, LA.	49 CFR 173.32(f)(5)	To authorize the transportation in commerce of a portable tank that is not filled to 80% capacity for a short distance by motor vehicle so that the portable tank can be topped off. (mode 1)
15531–N	National Aeronautics and Space Administration (NASA) Washington, DC.	49 CFR 173.302(a)	This request seeks relief from the requirement for the IV–TEPC Detectors to be DOT specification cylinders. The Detectors contain less than 0.04 grams of propane gas. Design details are provided to justify that the Detectors are constructed and packaged robustly, with multiple containment barriers. These Detectors have been deemed safe by NASA to fly onboard manned spacecraft. (modes 1, 2, 3, 4, 5, 6)
MODIFICATION SPECIAL PERMIT WITHDRAWN			
13736–M	ConocoPhillips Anchorage, AK.	49 CFR 172.101 Table, Col. (9B)	To modify the special permit to authorize an increase in the capacity from 350 to 4500 U.S. gallons for bulk containers.
EMERGENCY SPECIAL PERMIT WITHDRAWN			
14929–N	Alaska Island Air, Inc. Togiak, AK.	49 CFR 173.302(f)	To authorize the transportation in commerce of cylinders of compressed oxygen without rigid outer packaging within the State of Alaska when no other means of transportation exist. (mode 4)
15495–N	Dow Corning Corp Midland, MI.	49 CFR 180.407	To authorize the transportation in commerce of a MC331 cargo tank motor vehicle containing hydrogen chloride, refrigerated liquid that is past its test date. (mode 1)
DENIED			
12412–M	Request by FMC Corporation Tonawanda, NY December 07, 2011. To modify the special permit to allow hoses to remain attached to discharge outlets while in transportation.		
14813–N	Request by Organ Recovery Systems Des Plaines, IL January 30, 2012. To authorize the transportation of the LifePort Kidney Transporter by air without being accompanied by a person qualified to operate it.		
15266–N	Request by 3AL Testing Corp. Denver, CO November 16, 2011. To authorize the transportation in commerce of certain DOT 3AL 6061–T6 cylinders used exclusively in medical oxygen service to be requalified every 10 years rather than every 5 years.		
15405–N	Request by Giant Resource Recovery—Attalla, Inc. Attalla, AL November 30, 2011. To authorize the one-time transportation in commerce of aerosols in alternative packaging for the purposes of testing.		
15429–N	Request by Demex International Inc. Picayune, MS January 12, 2012. To authorize the transportation in commerce of certain explosives by vessel in an alternative stowage configuration.		
15464–N	Request by Alliant Techsystems Operations LLC. Eden Prairie, MN January 20, 2012. To authorize the transportation in commerce of ammunition and components that have been combined with non-hazardous materials and are being transported as hazardous waste without a new EX classification.		
14741–M	Weatherford International Fort Worth, TX.	49 CFR 173.304	To modify the special permit to authorize rail freight as an additional mode of transportation.

[FR Doc. 2012–2897 Filed 2–15–12; 8:45 am]

BILLING CODE 4909–60–M

DEPARTMENT OF THE TREASURY

Submission for OMB Review; Comment Request

February 13, 2012.

The Department of the Treasury will submit the following information collection request to the Office of Management and Budget (OMB) for review and clearance in accordance with the Paperwork Reduction Act of 1995, Public Law 104–13, on or after the date of publication of this notice.

DATES: Comments should be received on or before March 19, 2012 to be assured of consideration.

ADDRESSES: Send comments regarding the burden estimate, or any other aspect of the information collection, including suggestions for reducing the burden, to (1) Office of Information and Regulatory Affairs, Office of Management and Budget, Attention: Desk Officer for Treasury, New Executive Office Building, Room 10235, Washington, DC 20503, or email at *OIRA_Submission@OMB.EOP.GOV* and (2) Treasury PRA Clearance Officer, 1750 Pennsylvania Ave. NW., Suite 11020, Washington, DC 20220, or online at *www.PRAComment.gov.*

FOR FURTHER INFORMATION CONTACT: Copies of the submission(s) may be obtained by calling (202) 927–5331, email at *PRA@treasury.gov,* or the entire information collection request may be found at *www.reginfo.gov.*

Internal Revenue Service (IRS)

OMB Number: 1545–1004.

Type of Review: Extension without change of a currently approved collection.

Title: U.S. Income Tax Return for Real Estate Investment Trusts.

Form: 1120–REIT.

Abstract: Form 1120–REIT is filed by a corporation, trust, or association electing to be taxed as a REIT in order to report its income, and deductions, and to compute its tax liability. IRS uses Form 1120–REIT to determine whether the REIT has correctly reported its income, deductions, and tax liability.

Affected Public: Private Sector: Businesses or other for-profits.

Estimated Total Burden Hours: 142,203.

OMB Number: 1545–1029.

Type of Review: Extension without change of a currently approved collection.

Title: Low-Income Housing Credit Disposition Bond or Treasury Direct Account Application.

Form: 8693.

Abstract: Form 8693 is needed per IRC section 42(j)(6) to post bond or establish a Treasury Direct Account and waive the recapture requirements under section 42(j) for certain disposition of a building on which the low-income housing credit was claimed. Internal Revenue regulations section 301.7101–1 requires that the posting of a bond must be done on the appropriate form as determined by the Internal Revenue Service.

Affected Public: Private Sector: Businesses or other for-profits.

Estimated Total Burden Hours: 3,589.

OMB Number: 1545–1511.

Type of Review: Extension without change of a currently approved collection.

Title: REG–209828–96 (TD 8758—Final) Nuclear Decommissioning Funds; Revised Schedules of Ruling Amounts.

Abstract: The regulations revise the requirements for requesting a schedule of ruling amounts based on a formula or method.

Affected Public: Private Sector: Businesses or other for-profits.

Estimated Total Burden Hours: 100.

Dawn D. Wolfgang,

Treasury PRA Clearance Officer.

[FR Doc. 2012–3658 Filed 2–15–12; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF VETERANS AFFAIRS

National Research Advisory Council; Notice of Meeting

The Department of Veterans Affairs (VA) gives notice under Public Law 92–463 (Federal Advisory Committee Act) that the National Research Advisory Council will hold a meeting on Wednesday, February 22, 2012, in Conference Room 23, at 131 M Street NE., Washington, DC. The meeting will convene at 9 a.m. and end at 3:30 p.m. The meeting is open to the public.

The purpose of the Council is to provide external advice and review for VA's research mission. The agenda will include a review of the VA research portfolio and a summary of current budget allocations. The Council will also provide feedback on the direction/focus of VA's research initiatives.

No time will be allocated at this meeting for receiving oral presentations from the public. Interested members of the public may submit written statements for the Council's review to Margaret Hannon, Designated Federal Officer, Office of Research and Development (10P9), Department of Veterans Affairs, 810 Vermont Avenue NW., Washington, DC 20420, or by email at *Margaret.Hannon@va.gov.* Any member of the public wishing to attend the meeting or wishing further information should contact Ms. Hannon at (202) 443–5614.

Dated: February 13, 2012.

By direction of the Secretary.

Vivian Drake,

Committee Management Officer.

[FR Doc. 2012–3640 Filed 2–15–12; 8:45 am]

BILLING CODE P

FEDERAL REGISTER

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Part II

Environmental Protection Agency

40 CFR Parts 60 and 63

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044, FRL–9611–4]

RIN 2060–AP52; RIN 2060–AR31

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On May 3, 2011, under authority of Clean Air Act (CAA) sections 111 and 112, the EPA proposed both national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs) and standards of performance for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units (76 FR 24976). After consideration of public comments, the EPA is finalizing these rules in this action.

Pursuant to CAA section 111, the EPA is revising standards of performance in response to a voluntary remand of a final rule. Specifically, we are amending new source performance standards (NSPS) after analysis of the public comments we received. We are also finalizing several minor amendments, technical clarifications, and corrections to existing NSPS provisions for fossil fuel-fired EGUs and large and small industrial-commercial-institutional steam generating units.

Pursuant to CAA section 112, the EPA is establishing NESHAP that will require coal- and oil-fired EGUs to meet hazardous air pollutant (HAP) standards reflecting the application of the maximum achievable control technology. This rule protects air quality and promotes public health by reducing emissions of the HAP listed in CAA section 112(b)(1).

DATES: This final rule is effective on April 16, 2012. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of April 16, 2012.

ADDRESSES: The EPA established two dockets for this action: Docket ID. No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP action). All documents in the dockets are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information 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 through *http://www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility 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) 566–1741.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. William Maxwell, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5430; Fax number (919) 541–5450; Email address: *maxwell.bill@epa.gov*. For the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–4003; Fax number (919) 541–5450; Email address: *fellner.christian@epa.gov*.

SUPPLEMENTARY INFORMATION:

The information presented in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by the final standards are shown in Table 1 of this preamble.

TABLE 1—POTENTIALLY AFFECTED REGULATED CATEGORIES AND ENTITIES

Category	NAICS code [1]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by the federal government.
State/local/tribal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by states, tribes, or municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian country.

[1] North American Industry Classification System.
[2] 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 is meant to provide a guide for readers regarding entities likely to be affected by this action. To determine whether you, as owner or operator of a facility, company, business, organization, etc., will be regulated by this action, you should examine the applicability criteria in 40 CFR 60.40, 60.40Da, or 60.40c or in 40 CFR 63.9981. 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).

B. Where can I get a copy of this document?

In addition to being available in the dockets, an electronic copy of this action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature by the Administrator, a copy of the action 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.

C. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 16, 2012. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment (including any public hearing) can be raised during judicial review. This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule[.]'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

D. What are the costs and benefits of this final rule?

Consistent with Executive Order (EO) 13563, ''Improving Regulation and Regulatory Review,'' we have estimated the costs and benefits of the final rule. This rule will reduce emissions of HAP, including mercury (Hg), from the electric power industry. Installing the technology necessary to reduce emissions directly regulated by this rule will also reduce the emissions of directly emitted $PM_{2.5}$ and sulfur dioxide (SO_2), a $PM_{2.5}$ precursor. The benefits associated with these PM and SO_2 reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA estimates that this final rule will yield annual monetized benefits (in 2007$) of between $37 to $90 billion using a 3 percent discount rate and $33 to $81 billion using a 7 percent discount rate. The great majority of the estimates are attributable to co-benefits from reductions in $PM_{2.5}$-related mortality. The annual social costs, approximated by the sum of the compliance costs and monitoring and reporting costs, are $9.6 billion (2007$) and the annual quantified net benefits (the difference between benefits and costs) are $27 to $80 billion using a 3 percent discount rate or $24 to $71 billion using a 7 percent discount rate. It is important to note that the $PM_{2.5}$ co-benefits reported here contain uncertainty, due in part to the important assumption that all fine particles are equally potent in causing premature mortality and because many of the benefits are associated with reducing $PM_{2.5}$ levels at the low end of the concentration distributions examined in the epidemiology studies from which the $PM_{2.5}$-mortality relationships used in this analysis are derived.

The benefits of this rule outweigh costs by between 3 to 1 or 9 to 1 depending on the benefit estimate and discount rate used. The co-benefits are substantially attributable to the 4,200 to 11,000 fewer $PM_{2.5}$-related premature mortalities estimated to occur as a result of this rule. The EPA could not monetize some costs and important benefits, such as some Hg benefits and those for the HAP reduced by this final rule other than Hg. Upon considering these limitations and uncertainties, it remains clear that the benefits of this rule, referred to in short as the Mercury and Air Toxics Standards (MATS), are substantial and far outweigh the costs.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE FINAL RULE IN 2016

[Billions of 2007$] [a]

	3% Discount rate	7% Discount rate
Total Monetized Benefits [b]	$37 to $90	$33 to $81.
Partial Hg-related Benefits [c]	$0.004 to $0.006	$0.0005 to $0.001.
$PM_{2.5}$-related Co-benefits [b]	$36 to $89	$33 to $80.
Climate-related Co-Benefits [d]	$0.36	$0.36.
Total Social Costs [e]	$9.6	$9.6.
Net Benefits	$27 to $80	$24 to $71.
Non-monetized Benefits	Visibility in Class I areas. Other neurological effects of Hg exposure. Other health effects of Hg exposure. Health effects of ozone and direct exposure to SO_2 and NO_2. Ecosystem effects. Health effects from commercial and non-freshwater fish consumption. Health risks from exposure to non-mercury HAP.	

[a] All estimates are for 2016, and are rounded to two significant figures.

[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits. Benefits in this table are nationwide and are associated with directly emitted $PM_{2.5}$ and SO_2 reductions. The estimate of social benefits also includes CO_2-related benefits calculated using the social cost of carbon, discussed further in chapter 5 of the RIA. Mercury benefits were calculated using the baseline from proposal. The difference in emissions reductions between proposal and final does not substantially affect the Hg benefits.

[c] Based on an analysis of health effects due to recreational freshwater fish consumption.

[d] This table shows monetized CO_2 co-benefits that were calculated using the global average social cost of carbon estimate at a 3 percent discount rate. In section 5.6 of the Regulatory Impact Analysis (RIA) we also report the monetized CO_2 co-benefits using discount rates of 5 percent, 2.5 percent, and 3 percent (95th percentile).

[e] Total social costs are approximated by the compliance costs for both coal- and oil-fired units. This includes monitoring, recordkeeping, and reporting costs.

For more information on how EPA is addressing EO 13563, see the EO discussion in the Statutory and Executive Order Reviews section of this preamble.

II. Background Information on the NESHAP

On May 3, 2011, the EPA proposed this rule to address emissions of toxic air pollutants from coal and oil-fired electric generating units as required by the CAA. The proposal explained at length the statutory history and requirements leading to this rule, the factual and legal basis for the rule and its specific provisions, and the costs and benefits to the public health and environment from the proposed requirements.

The EPA received over 900,000 comments from members of the public on the proposed rule, substantially more than for any other prior regulatory proposal. The comments express concerns about the presence of Hg in the environment and the effect it has on human health, concerns about the costs of the rule, how challenging it may be for some sources to comply and questions about the impact it may have on this country's electricity supply and economy. Many comments provided additional information and data that have enriched the factual record and enabled EPA to finalize a rule that fulfills the mandate of the CAA while providing flexibility and compliance options to affected sources—options that make the rule less costly and compliance more readily manageable.

This rule establishes uniform emissions-control standards that sources can meet with proven and available technologies and operational processes in a timeframe that is achievable. They will put this industry, now the single largest source of Hg emissions in the United States (U.S.) with emissions of 29 tons per year, on a path to reducing those emissions by approximately 90 percent. Emissions of other toxic metals, such as arsenic (As) and nickel (Ni), dioxins and furans, acid gases (including hydrochloric acid (HCl) and SO_2) will also decrease dramatically with the installation of pollution controls. And the flexibilities established in this rule along with other available tools provide a clear pathway to compliance without jeopardizing the country's energy supply.

This preamble explains EPA's appropriate and necessary finding, the elements of the final rule, key changes the EPA is making in response to comments submitted on the proposed rule, and our responses to many of the comments we received. A full response to comments is provided in the response to comments document available in the docket for this rulemaking.

A. What is the statutory authority for this final rule?

Congress established a specific structure for determining whether to regulate EGUs under CAA section 112.[1] Specifically, Congress enacted CAA section 112(n)(1).

Section 112(n)(1)(A) of the CAA requires the EPA to conduct a study to evaluate the remaining public health hazards that are reasonably anticipated to occur as a result of EGUs' HAP emissions after imposition of CAA requirements. The EPA must report the results of that study to Congress, and regulate EGUs ''if the Administrator finds such regulation is appropriate and necessary,'' after considering the results of that study. Thus, CAA section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under CAA section 112. *See New Jersey* v. *EPA*, 517 F.3d 574 at 582 (D.C. Cir. 2008) (''Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs.'').

As directed, the EPA conducted the study to evaluate the remaining public health hazards and reported the results to Congress (Utility Study Report to Congress (Utility Study)).[2] We discuss this study below in conjunction with other studies that CAA section 112(n)(1) requires concerning EGUs. See also 76 FR 24982–24984 (summarizing studies).

Once the EPA lists a source category pursuant to CAA section 112(c), the EPA must then establish technology-based emission standards under CAA section 112(d). For major sources, the 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 EPA determines are achievable taking into account certain statutory factors. *See* CAA section 112(d)(2). These standards are referred to as ''maximum achievable control technology'' or ''MACT'' standards. The MACT standards for existing sources must be at least as stringent as the average emission limitation achieved by the best performing 12 percent of existing sources in the category (for which the Administrator has emissions information) or the best performing 5 sources for source categories with less than 30 sources. *See* CAA section 112(d)(3)(A) and (B), respectively. This level of minimum stringency is referred to as the ''MACT floor,'' and the EPA cannot consider cost in setting the floor. For new sources, MACT standards must be at least as stringent as the control level achieved in practice by the best controlled similar source. *See* CAA section 112(d)(3).

The EPA also must consider more stringent ''beyond-the-floor'' control options. When considering beyond-the-floor options, the EPA must consider the maximum degree of reduction in HAP emissions and take into account costs, energy, and non-air quality health and environmental impacts when doing so. *See Cement Kiln Recycling Coal.* v. *EPA*, 255 F.3d 855, 857–58 (D.C. Cir. 2001).

Alternatively, the EPA may set a health-based standard for HAP that have an established health threshold, and the standard must provide ''an ample margin of safety.'' *See* CAA section 112(d)(4). As these standards could be less stringent than MACT standards, the Agency must have detailed information on HAP emissions from the subject sources and sources located near the subject sources before exercising its discretion to set such standards.

For area sources, the EPA may issue standards or requirements that provide for the use of generally available control technologies or management practices (GACT standards) in lieu of promulgating MACT or health-based standards. *See* CAA section 112(d)(5).

As noted above, CAA section 112(n) requires completion of various reports concerning EGUs. For the first report, the Utility Study, Congress required the EPA to evaluate the hazards to public health reasonably anticipated to occur as the result of HAP emissions from EGUs after imposition of the requirements of the CAA. *See* CAA section 112(n)(1)(A). The EPA was required to report results from this study to Congress by November 15, 1993. *Id.* Congress also directed the EPA to conduct ''a study of mercury emissions from [EGUs], municipal waste combustion units, and other sources, including area sources'' (Mercury Study). *See* CAA section 112(n)(1)(B). The EPA was required to report the results from this study to Congress by November 15, 1994. *Id.* In conducting this Mercury Study, Congress directed the EPA to ''consider the rate and mass of such emissions, the health and environmental effects of such emissions, technologies which are available to control such emissions, and the costs of such technologies.'' *Id.* Congress directed the National Institute of Environmental Health Sciences (NIEHS) to conduct the last required evaluation, ''a study to determine the threshold level of mercury exposure below which adverse human health effects are not expected to occur'' (NIEHS Study). *See* CAA section 112(n)(1)(C). The NIEHS was required to submit the results to Congress by November 15, 1993. *Id.* In conducting this study, NIEHS was to determine ''a threshold for mercury concentrations in the tissue of fish which may be consumed (including consumption by sensitive populations) without adverse effects to public health.'' *Id.*

In addition, Congress, in conference report language associated with the EPA's fiscal year 1999 appropriations, directed the EPA to fund the National Academy of Sciences (NAS) to perform an independent evaluation of the available data related to the health impacts of methylmercury (MeHg) (NAS Study or MeHg Study). H.R. Conf. Rep. No 105–769, at 281–282 (1998). Specifically, Congress required NAS to advise the EPA as to the appropriate reference dose (RfD) for MeHg. 65 FR 79826. The RfD is the amount of a chemical which, when ingested daily over a lifetime, is anticipated to be without adverse health effects to humans, including sensitive subpopulations. In the same conference report, Congress indicated that the EPA should not make the appropriate and necessary regulatory determination for Hg emissions until the EPA had reviewed the results of the NAS Study. *See* H.R. Conf. Rep. No 105–769, at 281–282 (1998).

As directed by Congress through different vehicles, the NAS Study and the NIEHS Study evaluated the same issues. The NIEHS completed the NIEHS Study in 1995,[3] and the NAS completed the NAS Study in 2000.[4] Because NAS completed its study 5 years after the NIEHS Study, and considered additional information not earlier available to NIEHS, for purposes of this document we discuss the content of the NAS Study as opposed to the NIEHS Study.

The EPA conducted the studies required by CAA section 112(n)(1) concerning utility HAP emissions, the Utility Study and the Mercury Study,[5] and completed both by 1998. Prior to issuance of the Mercury Study, the EPA

[1] ''Electric utility steam generating unit'' is defined, in part, as any ''fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.'' *See* CAA section 112(a)(8).

[2] U.S. EPA. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress. EPA–453/R–98–004a. February 1998.

[3] NIEHS Study, August 1995; EPA–HQ–OAR–2009–3053.

[4] National Research Council (NAS). 2000. Toxicological Effects of Methylmercury. Committee on the Toxicological Effects of Methylmercury, Board on Environmental Studies and Toxicology, National Research Council.

[5] Mercury Study Report to Congress, December 1997; EPA–HQ–OAR–2009–0234–3054.

engaged in two extensive external peer reviews of the document.

On December 20, 2000, the EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under CAA section 112(d). In making that finding, the EPA considered the Utility Study, the Mercury Study, the NAS Study, and certain additional information, including information about Hg emissions from coal-fired EGUs that the EPA obtained pursuant to an information collection request (ICR) under the authority of CAA section 114. 65 FR 79826–27.

B. What is the litigation history of this final rule?

Shortly after issuance of the December 2000 finding, an industry group challenged that finding in the Court of Appeals for the D.C. Circuit (D.C. Circuit). *Utility Air Regulatory Group (UARG)* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001). The D.C. Circuit dismissed the lawsuit holding that it did not have jurisdiction because CAA section 112(e)(4) 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 section 7607 of (the CAA) when the Administrator issues emission standards for such pollutant or category.'' *Id. (emphasis added).*

Pursuant to a settlement agreement, the deadline for issuing emission standards was March 15, 2005. However, instead of issuing emission standards pursuant to CAA section 112(d), on March 29, 2005, the EPA issued the Section 112(n) Revision Rule (2005 Action). That action delisted EGUs after finding that it was neither appropriate nor necessary to regulate such units under CAA section 112. In addition, on May 18, 2005, the EPA issued the Clean Air Mercury Rule (CAMR). 70 FR 28606. That rule established standards of performance for emissions of Hg from new and existing coal-fired EGUs pursuant to CAA section 111.

Environmental groups, states, and tribes challenged the 2005 Action and CAMR. Among other things, the environmental and state petitioners argued that the EPA could not remove EGUs from the CAA section 112(c) source category list without following the requirements of CAA section 112(c)(9).

On February 8, 2008, the D.C. Circuit vacated both the 2005 Action and CAMR. The D.C. Circuit held that the EPA failed to comply with the requirements of CAA section 112(c)(9) for delisting source categories. Specifically, the D.C. Circuit held that CAA section 112(c)(9) applies to the removal of ''any source category'' from the CAA section 112(c) list, including EGUs. The D.C. Circuit found that, by enacting CAA section 112(c)(9), Congress limited the EPA's discretion to reverse itself and remove source categories from the CAA section 112(c) list. The D.C. Circuit found that the EPA's contrary position would ''nullify § 112(c)(9) altogether.'' *New Jersey* v. *EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008). The D.C. Circuit did not reach the merits of petitioners' arguments on CAMR, but vacated CAMR for existing sources because coal-fired EGUs were already listed sources under CAA section 112. The D.C. Circuit reasoned that even under the EPA's own interpretation of the CAA, regulation of existing sources' Hg emissions under CAA section 111 was prohibited if those sources were a listed source category under CAA section 112.[6] *Id.* The D.C. Circuit vacated and remanded CAMR for new sources because it concluded that the assumptions the EPA made when issuing CAMR for new sources were no longer accurate (*i.e.*, that there would be no CAA section 112 regulation of EGUs and that the CAA section 111 standards would be accompanied by standards for existing sources). *Id.* at 583–84. Thus, CAMR and the 2005 Action became null and void.

On December 18, 2008, several environmental and public health organizations filed a complaint in the U.S. District Court for the District of Columbia.[7] They alleged that the Agency had failed to perform a nondiscretionary duty under CAA section 304(a)(2), by failing to promulgate final CAA section 112(d) standards for HAP from coal- and oil-fired EGUs by the statutorily-mandated deadline, December 20, 2002, 2 years after such sources were listed under CAA section 112(c). The EPA settled that litigation. The consent decree resolving the case requires the EPA to sign a notice of proposed rulemaking setting forth the EPA's proposed CAA section 112(d) emission standards for coal- and oil-fired EGUs by March 16, 2011, and a notice of final rulemaking by December 16, 2011.[8]

C. What is the relationship between this final rule and other combustion rules?

1. CAA Section 111

The EPA promulgated revised NSPS for SO_2, nitrogen oxides (NO_X), and PM under CAA section 111 for EGUs (40 CFR part 60, subpart Da) and industrial boilers (IB) (40 CFR part 60, subparts Db and Dc) on February 27, 2006 (71 FR 9866). As noted elsewhere, in this action we are finalizing certain amendments to 40 CFR part 60, subpart Da. In developing this final rule, we considered the monitoring, testing, and recordkeeping requirements of the existing and revised NSPS to avoid duplicating requirements to the extent possible.

2. CAA Section 112

The EPA has previously developed other non-EGU combustion-related NESHAP under CAA section 112(d). The EPA promulgated final NESHAP for major source industrial, commercial and institutional boilers and process heaters (IB) and area source industrial, commercial and institutional boilers on March 21, 2011 (40 CFR part 63, subpart DDDDD, 76 FR 15608; and subpart JJJJJJ, 76 FR 15249, respectively), and promulgated standards for stationary combustion turbines (CT) on March 5, 2004 (40 CFR part 63 subpart YYYY; 69 FR 10512). In addition to these three NESHAP, on March 21, 2011, the EPA also promulgated final CAA section 129 standards for commercial and institutional solid waste incineration (CISWI) units, including energy recovery units (40 CFR part 60, subparts CCCC (NSPS) and DDDD (emission guidelines); 76 FR 15704); and a definition of non-hazardous secondary materials that are solid waste (Non-hazardous Solid Waste Definition Rule (40 CFR part 241, subpart B; 76 FR 15456)). Electric generating units and IB

[6] In CAMR and the 2005 Action, EPA interpreted section 111(d) of the Act as prohibiting the Agency from establishing an existing source standard of performance under CAA section 111(d) for any HAP emitted from a particular source category, if the source category is regulated under CAA section 112.

[7] American Nurses Association, Chesapeake Bay Foundation, Inc., Conservation Law Foundation, Environment America, Environmental Defense Fund, Izaak Walton League of America, Natural Resources Council of Maine, Natural Resources Defense Council, Physicians for Social Responsibility, Sierra Club, The Ohio Environmental Council, and Waterkeeper Alliance, Inc. (Civ. No. 1:08–cv–02198 (RMC)).

[8] The consent decree originally required EPA to sign a notice of final rulemaking no later than November 16, 2011; however, on October 21, 2011, pursuant to paragraph 6 of the consent decree, the parties agreed to a 30-day extension of the final rule deadline. As stated in the stipulation memorializing the extension, the parties agreed to the extension of 30 days because EPA provided an additional 30 days for public comment and the time was necessary to respond to comments submitted on the proposed rule.

that combust fossil fuel and solid waste, as that term is defined by the Administrator pursuant to the Resource Conservation and Recovery Act (RCRA), *see* 76 FR 15456, will be subject to standards issued pursuant to CAA section 129 (*e.g.*, CISWI), unless they meet one of the exemptions in CAA section 129(g)(1). Clean Air Act section 129 standards are discussed in more detail below.

The two IB (Boiler) NESHAP, the CT NESHAP, and this final rule will regulate HAP emissions from sources that combust fossil fuels for electrical power, process operations, or heating. The differences among these rules are due to the size of the units (megawatt (MW), megawatt-electric (MWe), or British thermal unit per hour (Btu/hr)), the boiler/furnace technology, and/or the portion of their electrical output (if any) for sale to any utility power distribution systems.

Pursuant to the CAA, an EGU is ''any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit.'' CAA section 112(a)(8). We consider all of the MW ratings quoted in the final rule to be the original rated nameplate capacity of the unit. We consider cogeneration to be the simultaneous production of power (electricity) and another form of useful thermal energy (usually steam or hot water) from a single fuel-consuming process.

We consider any combustion unit, regardless of size, that produces steam to serve a generator that produces electricity exclusively for industrial, commercial, or institutional purposes (*i.e.*, makes no sales to the national electrical distribution grid) to be an IB unit. We do not consider a fossil fuel-fired combustion unit that serves a generator that produces electricity for sale to be an EGU under the final rule if the size of the combustion unit is less than or equal to 25 MW. Units that are 25 MW or less are likely subject to one of the two Boiler NESHAP.

Because of the combustion technology of simple-cycle and combined-cycle stationary CTs (with the exception of integrated gasification combined cycle (IGCC) units that burn gasified coal or petroleum coke synthesis gas/syngas), we do not consider these CTs to be EGUs for purposes of this final rule.[9]

The December 2000 listing discussed above did not list natural gas-fired EGUs. Thus, this final rule does not regulate a unit that otherwise meets the CAA section 112(a)(8) definition of an EGU but that combusts natural gas exclusively or natural gas in combination with another fossil fuel where the natural gas constitutes 90.0 percent or more of the average annual heat input during any 3 consecutive calendar years or 85.0 percent or more of the annual heat input in one calendar year. We consider such units to be natural gas-fired EGUs notwithstanding the combustion of some coal or oil (or derivative thereof) and such units are not subject to this final rule.

The CAA does not define the terms ''fossil fuel-fired'' and ''fossil fuel.'' In this rule, we are finalizing definitions for both terms for purposes of this rule. The definition of ''fossil fuel-fired'' will help determine the applicability of the final rule to combustion units that sell electricity to the utility power distribution system. The definition of ''fossil fuel-fired'' establishes the amount of fossil fuel combustion necessary to make a unit ''fossil fuel-fired'' and hence potentially subject to this final rule. These definitions will help determine applicability of the final rule to units that primarily fire non-fossil fuels (*e.g.*, biomass) but generally start up using either natural gas or distillate oil and may use these fuels (or coal) during normal operation for flame stabilization.

In addition, the EPA is finalizing in the definition of ''fossil fuel-fired'' that, among other things, an EGU must fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date in order to be considered a fossil fuel-fired EGU subject to this final rule. The EPA has based these threshold percentage values on the definition of ''oil-fired'' in the Acid Rain Program (ARP) found at 40 CFR 72.2. Though the EPA does not have annual heat input data for, for example, biomass co-fired EGUs because their use is not yet commonplace, we believe this definition accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this final rule.

[9] The CT NESHAP regulates HAP emissions from all simple-cycle and combined-cycle stationary CTs producing electricity or steam for any purpose.

Units that do not meet the EGU definition will in most cases be considered IB units subject to one of the two Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.*, less than or equal to 10.0 percent of the average annual heat input in any 3 consecutive calendar years or less than or equal to 15.0 percent of the annual heat input during any one calendar year) is not considered to be a fossil fuel-fired EGU under this final rule.

A cogeneration facility that sells electricity to any utility power distribution system equal to more than one-third of its potential electric output capacity and more than 25 MW will be considered an EGU if the facility is fossil fuel-fired as that term is defined in the final rule.

We recognize that different CAA section 112 rules may impact a particular unit at different times. For example, the Boiler NESHAP may cover some cogeneration units. Such a unit may decide to increase or decrease the proportion of production output it supplies to the electric utility grid, thus causing the unit to meet the EGU cogeneration criteria (*i.e.*, greater than one-third of its potential output capacity and greater than 25 MW). A unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the final EGU NESHAP.

Another rule intersection may occur where one or more coal- or oil-fired EGU(s) share an air pollution control device (APCD) and/or an exhaust stack with one or more similarly-fueled IB unit(s). To demonstrate compliance with two different rules, either the emissions would need to be apportioned to the appropriate source or the more stringent emission limit would need to be met. Data needed to apportion emissions are not currently required by this final rule or the final boiler NESHAP and are not otherwise available. Therefore, the EPA is finalizing the requirement to comply with the more stringent emission limit.

3. CAA Section 129

Clean Air Act section 129 regulates units that combust ''non-hazardous secondary materials,'' as that term is defined by the Administrator under the Resource Conservation and Recovery Act (RCRA), that are ''solid wastes.'' On March 21, 2011, the EPA promulgated the final Non-Hazardous Solid Waste Definition Rule (76 FR 15456). Any EGU that combusts any solid waste as defined in that final rule is a solid waste incineration unit subject to emissions standards under CAA section 129.

In the Non-Hazardous Solid Waste Definition Rule, the EPA determined that coal refuse from current mining operations is not considered to be a ''solid waste'' if it is not discarded. Coal refuse that is in legacy coal refuse piles is considered a ''solid waste'' because it has been discarded. However, if discarded coal refuse is processed in the same manner as currently mined coal refuse, the coal refuse would not be considered a solid waste but instead would be considered a product fossil fuel. Therefore, the combustion of such material by a combustion unit would not subject that unit to regulation under CAA section 129. Instead, the unit would be subject to this final rule if it meets the definition of EGU. In the proposed rule, we assumed that all units that combust coal refuse and otherwise meet the definition of a coal-fired EGU are in fact combusting newly mined coal refuse or coal refuse from legacy piles that has been processed such that it is not a solid waste. We did not receive any information since proposal that would cause us to revise this determination in the final rule.

Further, CAA section 129(g)(1)(B) exempts from regulation

> ''* * * qualifying small power production facilities, as defined in section 796(17)(C) of Title 16, or qualifying cogeneration facilities, as defined in section 796(18)(B) of Title 16, which burn homogeneous waste * * * for the production of electric energy or in the case of qualifying cogeneration facilities which burn homogeneous waste for the production of electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes * * *''

If the ''homogeneous waste'' material that such facilities combust is also a fossil fuel, and those facilities otherwise meet the definition of an EGU under CAA section 112(a)(8), then those facilities are exempt from regulation under CAA section 129 but covered under this final rule. For example, a qualifying small power production facility or cogeneration facility combusting only coal refuse that is a solid waste and a ''homogenous waste,'' as that term is defined in the final CAA section 129 CISWI standards, would be subject to this final rule if the unit also met the definition of EGU.

D. What are the health effects of pollutants emitted from coal- and oil-fired EGUs?

This final rule protects air quality and promotes public health by reducing emissions of some of the HAP listed in CAA section 112(b)(1). Utilities are by far the largest anthropogenic source of Hg in the U.S. In addition, EGUs are the largest source of HCl, hydrogen fluoride (HF), and selenium (Se) emissions, and a major source of metallic HAP emissions including As, chromium (Cr), Ni, and others. The discrepancy is even greater now that almost all other major source categories have been required to control Hg and other HAP under CAA section 112. In 2005, U.S. EGUs emitted 50 percent of total domestic anthropogenic Hg emissions, 62 percent of total As emissions, 39 percent of total cadmium (Cd) emissions, 22 percent of total Cr emissions, 82 percent of total HCl emissions, 62 percent of total HF emissions, 28 percent of total Ni emissions, and 83 percent of total Se emissions.[10] Exposure to these HAP, depending on exposure duration and levels of exposures, is associated with a variety of adverse health effects. These adverse health effects may include chronic health disorders (*e.g.*, irritation of the lung, skin, and mucus membranes; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). Two of the HAP are classified as human carcinogens (As and CrVI) and two as probable human carcinogens (Cd and Ni). *See* 76 FR 25003–25005 for a fuller discussion of the health effects associated with these pollutants.

III. Appropriate and Necessary Finding

A. Overview

In December 2000, the EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under section 112(d). The EPA found that it was appropriate to regulate HAP emissions from coal- and oil-fired EGUs because, among other reasons, Hg is a hazard to public health, and U.S. EGUs are the largest domestic source of Hg emissions. The EPA also found it appropriate to regulate HAP emissions from EGUs because it had identified certain control options that would effectively reduce HAP emissions from U.S. EGUs. The EPA found that it was necessary to regulate HAP emissions from U.S. EGUs under section 112 because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from HAP emissions from U.S. EGUs and that CAA section 112 is intended to address HAP emissions. *See* 76 FR 24984–20985 (for further discussion of 2000 finding).

Because several years had passed since the 2000 finding, the EPA performed additional technical analyses for the proposed rule, even though those analyses were not required. These analyses included a national-scale Hg risk assessment focused on populations with high levels of self-caught fish consumption, and a set of 16 case studies of inhalation cancer risks for non-Hg HAP. The analyses confirm that it remains appropriate and necessary to regulate U.S. EGUs under section 112.

In the preamble to the proposed rule, the EPA reported the results of those additional technical analyses. Those analyses confirmed the 2000 finding that it is appropriate to regulate U.S. EGUs under section 112 by demonstrating that (1) Hg continues to pose a hazard to public health because up to 28 percent of watersheds were estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the reference dose for methylmercury (MeHg RfD), a level above which there is increased risk of neurological effects in children, (2) non-Hg HAP emissions pose a hazard to public health because case studies at 16 facilities demonstrated that lifetime cancer risks at 4 of the facilities exceed 1 in 1 million, and (3) U.S. EGUs remain the largest domestic source of Hg emissions and several HAP (*e.g.*, HF, Se, HCl), and are among the largest contributors for other HAP (*e.g.*, As, Cr, Ni, HCN). Thus, in the preamble to the proposed rule, the EPA found that Hg and non-Hg HAP emissions from U.S. EGUs pose hazards to public health, which confirmed the 2000 finding and demonstrated that it remains appropriate to regulate U.S. EGUs under section 112.

In the preamble to the proposed rule, the EPA also found that it is appropriate to regulate U.S. EGUs because (1) Hg emissions pose a hazard to the environment and wildlife, adversely impacting species of fish-eating birds and mammals, (2) acid gas HAP pose a hazard to the environment because they contribute to aquatic acidification, and (3) effective controls are available to reduce Hg and non-Hg HAP emissions from U.S. EGUs.

The additional analyses reported in the preamble to the proposed rule also confirmed that it remains necessary to regulate U.S. EGU under CAA section 112. These analyses demonstrated that (1) Hg emissions from U.S. EGUs remaining in 2016 are reasonably anticipated to pose a hazard to public health after imposition of other CAA

[10] From 2005 National-Scale Air Toxics Assessment (NATA), available at *http://www.epa.gov/ttn/atw/nata2005/*.

requirements, such as the Cross-State Air Pollution Rule (CSAPR); (2) U.S. EGUs are reasonably anticipated to remain the largest source of Hg in the U.S. and thus contribute to the risk associated with exposure to MeHg; (3) Hg emissions from U.S. EGUs after imposition of the requirements of the CAA were projected to be 29 tons per year in 2016, similar to levels of Hg emitted today, indicating that further substantial reductions in Hg emissions are not reasonably anticipated without federal regulations on Hg from U.S. EGUs; (4) we cannot be certain that the identified cancer risks attributable to non-Hg emissions from U.S. EGUs will be addressed through imposition of the requirements of the CAA because companies can use compliance strategies for criteria pollutants that do not achieve HAP co-benefits (*e.g.*, purchasing allowances in a trading program); and (5) we cannot ensure that Hg and non-Hg HAP emissions reductions achieved since 2005 would be permanent without federally binding regulations for Hg from U.S. EGUs.

Since issuance of the proposed rule, the EPA has conducted peer reviews of the national-scale Hg risk assessment (Hg Risk TSD) and the approach for estimating chromium and nickel inhalation cancer risk in the case studies.[11] [12] The peer review of the Hg Risk TSD was conducted by EPA's independent Science Advisory Board (SAB). The SAB stated that it ''supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs.'' [13] SAB recommended several improvements to the data, methods and documentation of the analyses, which EPA has fully addressed in the revised Hg Risk TSD.

As described in the revised Hg Risk TSD, after addressing comments from the peer review, the revised results show that up to 29 percent of modeled watersheds are estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the MeHg RfD, an increase of one percentage point from the results reported in the proposed rule. We conclude that Hg emissions from EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds at risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone without considering deposition from other sources would lead to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition.[14] [15] Each of these results independently supports our conclusion that Hg emissions from EGUs pose hazards to public health.

The peer review of the approach to estimate Ni and Cr cancer risk in the case studies also supported EPA's assessment. The EPA enhanced this analysis in response to the peer review and public comments. The results of those revised analyses show that 6 of 16 modeled facilities have lifetime cancer risks greater than 1 in a million, thus confirming that non-Hg HAP emissions from U.S. EGUs remain a hazard to public health. Given Congress' determination that categories of sources that emit HAP resulting in a lifetime cancer risk greater than 1 in a million should not be removed from the CAA section 112(c) source category list and should continue to be regulated under CAA section 112, the EPA concludes that risk above that level represents a hazard to public health.

Based on our consideration of the peer reviews, public comments, and our updated analyses, we confirm the findings that Hg and non-Hg HAP emissions from U.S. EGUs pose hazards to public health and that it remains appropriate to regulate U.S. EGUs under CAA section 112. We also conclude that it remains appropriate to regulate U.S. EGUs under CAA section 112 because of the magnitude of Hg and non-Hg emissions, environmental effects of Hg and certain non-Hg emissions, and the availability of controls to reduce HAP emissions from EGUs.

In addition, we conclude that the hazards to public health from Hg and non-Hg emissions from U.S. EGUs are reasonably anticipated to remain after imposition of the requirements of the CAA. The same is true for hazards to the environment. Thus, we confirm that it is necessary to regulate U.S. EGUs under CAA section 112.

B. Peer Review of the Hg Risk TSD Supporting the Appropriate and Necessary Finding for Coal and Oil-Fired EGUs and EPA Response

In the preamble to the proposed rule, the EPA stated that ''in making the finding that it remains appropriate and necessary to regulate EGUs to address public health and environmental hazards associated with emissions of Hg and Non-Hg HAP from EGUs, the EPA determined that the Hg Risk TSD supporting EPA's 2011 review of U.S. EGU health impacts should be peer-reviewed.'' [16] We also indicated that due to the court-ordered schedule for the final rule, we planned to conduct the peer review as expeditiously as possible after issuance of the proposed rule, and that the results of the peer review and any EPA response would be published before the final rule. Due to the extension of the public comment period and the volume of public comments received on the analyses supporting the proposed rule, we were unable to publish EPA's response prior to signature of the final rule.

The EPA's response to the peer review the Hg Risk TSD is fully documented in the revised *Technical Support Document (TSD): National-Scale Assessment of Hg Risk to Populations of High Consumption of Self-Caught Fish In Support of the Appropriate and Necessary Finding for Coal and Oil-Fired Electric Generating Units.*[17] The following sections describe the peer review process that we followed, provide the peer review charge questions presented to the peer review panel, summarize the key recommendations from the peer review, and summarize our responses to those recommendations.

[11] U.S. EPA. 2011a. *National-Scale Assessment of Mercury Risk to Populations with High Consumption of Self-caught Freshwater Fish In Support of the Appropriate and Necessary Finding for Coal- and Oil-Fired Electric Generating Units.* Office of Air Quality Planning and Standards. November. EPA–452/R–11–009.

[12] U.S. EPA. 2011b. *Supplement to Non-mercury Case Study Chronic Inhalation Risk Assessment for the Utility MACT Appropriate and Necessary Analysis.* Office of Air Quality Planning and Standards. November.

[13] U.S. Environmental Protection Agency-Science Advisory Board (U.S. EPA–SAB). 2011. Peer Review of EPA's Draft National-Scale Mercury Risk Assessment. EPA–SAB–11–017. September. Available on the Internet at *http://yosemite.epa.gov/sab/sabproduct.nsf/BCA23C5B7917F5BF8525791A0072CCA1/$File/EPA-SAB-11-017-unsigned.pdf.*

[14] Because some watersheds with exposures sufficient to exceed the RfD with Hg deposition from U.S. EGUs alone without considering deposition from other sources also have U.S. EGU contributions of more than 5 percent of total Hg deposition, there is some overlap between the two risk metrics. This explains why the total percent of watersheds exceeding either risk metric is less than the sum of the individual risk metrics.

[15] Requiring at least a 5 percent EGU contribution is a conservative approach given the increasing risks associated with incremental exposures above the RfD. Because we are finding 24 percent of watersheds with populations potentially at risk even using this conservative approach, we have confidence that emissions of Hg from U.S. EGUs are causing a hazard to public health.

[16] 76 FR 25012.

[17] U.S. EPA, 2011a.

1. Summary of Peer Review Process

Peer review is consistent with EPA's open and transparent process to ensure that the Agency's scientific assessments and rulemakings are based on the best science available. This regulatory action was supported by the Hg Risk TSD, which is a highly influential scientific assessment. Therefore, the EPA conducted a peer review in accordance with OMB's *Final Information Quality Bulletin for Peer Review*[18] as described below. All the materials related to the peer review, including the SAB's final report, can be found in the docket for this rulemaking.

The EPA commissioned the peer review through EPA's SAB, which provides independent advice and peer review to EPA's Administrator on the scientific and technical aspects of environmental issues. The SAB convened a 22-member peer review committee. The SAB process for selecting the panel began with two **Federal Register** Notices requesting nominations for the *Mercury Review Panel.*[19] Based on nominations received, a list of potential panel members, along with bio-sketches, was posted for public comment on the SAB Web site on April 15, 2011. The members of the *Mercury Review Panel* were announced on May 24, 2011. The membership of the panel included representatives of 16 academic institutions, 4 state health or environmental agencies, 1 federal agency, and 1 utility industry organization.[20] The panel held a public meeting in Research Triangle Park, NC, on June 15–17, 2011, which included the opportunity for public comment on the Hg Risk TSD and the peer review process.[21] At the June 15–17 public meeting, the panel completed a draft peer review report. The minutes of that meeting and the draft peer review report were posted to the SAB public Web site within the public comment period for the proposed rule. The panel discussed the draft report at a public teleconference on July 12, 2011, during which additional opportunities for public comment were provided,[22] and submitted a revised draft for quality review by the Chartered SAB before the end of the public comment period on the rule. The Chartered SAB held a public teleconference on September 7, 2011, to conduct a quality review of the draft report; this teleconference also included a final opportunity for public comment.[23] The SAB submitted its final report to EPA on September 29, 2011.[24] Notice of all the meetings was published in the **Federal Register** and all of the materials discussed at the SAB meetings, including technical documents, presentations, meeting minutes, and draft reports were posted for public access on the SAB Web site[25] and were added to the docket for the final rule on October 14, 2011.

2. Peer Review Charge Questions

The EPA asked the SAB to comment on the Hg Risk TSD, including the overall design and approach and the use of specific models and key assumptions. The EPA also asked the SAB to comment on the extent to which specific facets of the assessment were well characterized in the Hg Risk TSD. The specific charge questions are listed below:

Question 1. Please comment on the scientific credibility of the overall design of the mercury risk assessment as an approach to characterize human health exposure and risk associated with U.S. EGU mercury emissions (with a focus on those more highly exposed).

Question 2. Are there any additional critical health endpoint(s) besides IQ loss, which could be quantitatively estimated with a reasonable degree of confidence to supplement the mercury risk assessment (*see* section 1.2 of the Mercury Risk TSD for an overview of the risk metrics used in the risk assessment)?

Question 3. Please comment on the benchmark used for identifying a potentially significant public health impact in the context of interpreting the IQ loss risk metric (i.e., an IQ loss of 1 to 2 points or more representing a potential public health hazard). Is there any scientifically credible alternate decrement in IQ that should be considered as a benchmark to guide interpretation of the IQ risk estimates (*see* section 1.2 of the Mercury Risk TSD for additional detail on the benchmark used for interpreting the IQ loss estimates)?

Question 4: Please comment on the spatial scale used in defining watersheds that formed the basis for risk estimates generated for the analysis (i.e., use of 12-digit hydrologic unit code classification). To what extent do [Hydrologic Unit Code] HUC12 watersheds capture the appropriate level of spatial resolution in the relationship between changes in mercury deposition and changes in MeHg fish tissue levels? (see section 1.3 and Appendix A of the Mercury Risk TSD for additional detail on specifying the spatial scale of watersheds used in the analysis).

Question 5: Please comment on the extent to which the fish tissue data used as the basis for the risk assessment are appropriate and sufficient given the goals of the analysis. Please comment on the extent to which focusing on data from the period after 1999 increases confidence that the fish tissue data used are more likely to reflect more contemporaneous patterns of Hg deposition and less likely to reflect earlier patterns of Hg deposition. Are there any additional sources of fish tissue MeHg data that would be appropriate for inclusion in the risk assessment?

Question 6: Given the stated goal of estimating potential risks to highly exposed populations, please comment on the use of the 75th percentile fish tissue MeHg value (reflecting targeting of larger but not the largest fish for subsistence consumption) as the basis for estimating risk at each watershed. Are there scientifically credible alternatives to use of the 75th percentile in representing potential population exposures at the watershed level?

Question 7: Please comment on the extent to which characterization of consumption rates and the potential location for fishing activity for high-end self-caught fish consuming populations modeled in the analysis are supported by the available study data cited in the Mercury Risk TSD. In addition, please comment on the extent to which consumption rates documented in Section 1.3 and in Appendix C of the Mercury Risk TSD provide appropriate representation of high-end fish consumption by the subsistence population scenarios used in modeling exposures and risk. Are there additional data on consumption behavior in subsistence populations active at inland freshwater water bodies within the continental U.S.?

Question 8: Please comment on the approach used in the risk assessment of

[18] Office of Management and Budget (OMB). 2004. *Final Information Quality Bulletin for Peer Review.* December. Available on the Internet at *http://www.whitehouse.gov/omb/memoranda_fy2005_m05-03.*

[19] 76 FR 10896 and 76 FR 17649. The first notice requested nominations to a Clean Air Scientific Advisory Committee (CASAC) panel. Upon review of the scope of the CASAC charter (resulting from a public comment received in response to the first notice), the SAB determined that it would be more appropriate to form a panel under the SAB, rather than CASAC. The second notice announced this change and requested nominations for the SAB panel.

[20] The full list of panel members is documented at *http://yosemite.epa.gov/sab/sabproduct.nsf/0/9F048172004D93BB8525783900503486/$File/Determination%20memo%20with%20addendum-05.24.11.pdf.*

[21] 76 FR 29746.

[22] 76 FR 39102.

[23] 76 FR 50729.

[24] U.S. EPA–SAB, 2011. Peer Review of EPA's Draft National-Scale Mercury Risk Assessment.

[25] *See http://yosemite.epa.gov/sab/sabpeople.nsf/WebCommittees/BOARD.*

assuming that a high-end fish consuming population could be active at a watershed if the ''source population'' for that fishing population is associated with that watershed (e.g., at least 25 individuals of that population are present in a U.S. Census tract intersecting that watershed). Please identify any additional alternative approaches for identifying the potential for population exposures in watersheds and the strengths and limitations associated with these alternative approaches (additional detail on how EPA assessed where specific high-consuming fisher populations might be active is provided in section 1.3 and Appendix C of the Mercury Risk TSD).

Question 9: Please comment on the draft risk assessment's characterization of the limitations and uncertainty associated with application of the Mercury Maps approach (including the assumption of proportionality between changes in mercury deposition over watersheds and associated changes in fish tissue MeHg levels) in the risk assessment. Please comment on how the output of CMAQ [Community Multiscale Air Quality] modeling has been integrated into the analysis to estimate changes in fish tissue MeHg levels and in the exposures and risks associated with the EGU-related fish tissue MeHg fraction (*e.g.,* matching of spatial and temporal resolution between CMAQ modeling and HUC12 watersheds). Given the national scale of the analysis, are there recommended alternatives to the Mercury Maps approach that could have been used to link modeled estimates of mercury deposition to monitored MeHg fish tissue levels for all the watersheds evaluated? (additional detail on the Mercury Maps approach and its application in the risk assessment is presented in section 1.3 and Appendix E of the Mercury Risk TSD).

Question 10: Please comment on the EPA's approach of excluding watersheds with significant non-air loadings of mercury as a method to reduce uncertainty associated with application of the Mercury Maps approach. Are there additional criteria that should be considered in including or excluding watersheds?

Question 11: Please comment on the specification of the concentration-response function used in modeling IQ loss. Please comment on whether EPA, as part of uncertainty characterization, should consider alternative concentration-response functions in addition to the model used in the risk assessment. Please comment on the extent to which available data and methods support a quantitative treatment of the potential masking effect of fish nutrients (*e.g.,* omega-3 fatty acids and selenium) on the adverse neurological effects associated with mercury exposure, including IQ loss (detail on the concentration-response function used in modeling IQ loss can be found in section 1.3 of the Mercury Risk TSD).

Question 12: Please comment on the degree to which key sources of uncertainty and variability associated with the risk assessment have been identified and the degree to which they are sufficiently characterized.

Question 13: Please comment on the draft Mercury Risk TSD's discussion of analytical results for each component of the analysis. For each of the components below, please comment on the extent to which EPA's observations are supported by the analytical results presented and whether there is a sufficient characterization of uncertainty, variability, and data limitations, taking into account the models and data used: Mercury deposition from U.S. EGUs, fish tissue MeHg concentrations, patterns of Hg deposition with HG fish tissue data, percentile risk estimates, and number and frequency of watersheds with populations potentially at risk due to U.S. EGU mercury emissions.

Question 14: Please comment on the degree to which the final summary of key observations in Section 2.8 is supported by the analytical results presented. In addition, please comment on the degree to which the level of confidence and precision in the overall analysis is sufficient to support use of the risk characterization framework described on page 18.

3. Summary of Peer Review Findings and Recommendations

The SAB was generally supportive of EPA's approach.[26] The SAB concluded, ''[i]n summary, based on its review of the draft Technical Support Document and additional information provided by EPA representatives during the public meetings, the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs.'' [27] The SAB further concluded, ''[t]he SAB regards the design of the risk assessment as suitable for its intended purpose, to inform decision-making regarding an 'appropriate and necessary finding' for regulation of hazardous air pollutants from coal and oil-fired EGUs, provided that our recommendations are fully considered in the revision of the assessment.'' [28]

The SAB report contained many recommendations for improving the Hg Risk TSD, which the SAB organized into three general themes: (1) Improve the clarity of the Hg Risk TSD regarding methods and presentation of results, (2) expand the discussion of sources of variability and uncertainty, and (3) de-emphasize IQ loss as an endpoint. In the following subsection, we provide EPA's response to these recommendations.

4. The EPA's Responses to Peer Review Recommendations

In response to the peer review, the EPA has substantially revised the Hg Risk TSD. The revised Hg Risk TSD addresses all of the recommendations from the SAB and includes a detailed list of the specific revisions made to the Hg Risk TSD. Revisions in response to the main recommendations are summarized below. Italicized statements are the SAB's recommendations, which are followed by EPA's response.

- *The watershed-focus of the Hg Risk TSD should be clearly stated early in the introduction to the document.* We have stated clearly in the introduction to the revised Hg Risk TSD that the focus of the analysis is on scenarios of high fish consumption by subsistence level fishing populations, assessed at watersheds where there is the potential for such subsistence fishing activity. Specifically, we modeled risk for a set of subsistence fisher scenarios at those watersheds where (a) we have measured fish tissue Hg data and (b) it is reasonable to assume that subsistence-level fishing activity could occur. We emphasize the point that the analysis is not a representative population-weighted assessment of risk. Rather, it is based on evaluating these potential exposure scenarios.
- *Because IQ does not fully capture the range of neurodevelopmental effects associated with Hg exposure, analysis of this endpoint should be deemphasized (and moved to an appendix) and primary focus should be placed on the MeHg RfD-based hazard quotient metric.* We modified the structure of the revised Hg Risk TSD accordingly.
- *Clarify the rationale for using a Hazard Quotient (HQ) at or above 1.5 as the basis for selecting potentially impacted watersheds.* The SAB fully supported using HQ as the risk metric, but we revised the discussion in the Hg Risk TSD to clarify why we selected 1.5

[26] U.S. EPA–SAB, 2011.

[27] *Id.*

[28] *Id.*

as the benchmark. We clarified that exposures above the RfD (*i.e.,* an HQ above one) represent increasing risk of neurological health effects.[29] We further clarified that the HQ is calculated to only one significant digit, based on the precision in the underlying RfD calculations. As a result, rounding convention requires that any values at or above 1.5 be expressed as an HQ of 2, while any values below 1.5 (*e.g.,* 1.49) be rounded to an HQ of 1. Thus, MeHg exposures leading to an HQ at or above 1.5 for pregnant women are considered above the RfD and are associated with increased risk of neurological health effects in children born to those mothers.

• *Regarding the fish tissue dataset used in the Hg Risk TSD, clarify which species of Hg is reflected in the underlying samples and discuss the implications of differences across states in sampling protocols in introducing bias into the analysis.* We clarified that in most cases, the fish tissue is measured for total Hg. Furthermore, based on the scientific literature,[30] it is reasonable to assume that more than 90 percent of fish tissue Hg is MeHg. Therefore, we incorporated an Hg conversion factor [31] into our exposure calculations to account for the fraction of total Hg that is MeHg in fish. We also expanded the discussion of uncertainty to address the potential for different sampling protocols across states to introduce bias into the Hg Risk TSD.

• *Additional detail should be provided on the characteristics of the fish tissue Hg dataset, including its derivation and the distribution of specific attributes across the dataset (e.g., number of fish tissue samples and number of different waterbodies in a watershed, number of species reflected across watersheds).* We included additional figures and tables describing the derivation of the watershed-level fish tissue Hg dataset, including the filtering steps applied to the original water body level data and the additional steps taken to generate the watershed-level fish tissue Hg percentile estimates. In addition, we included tables summarizing key attributes of the dataset (*e.g.,* distribution of fish tissue sample size and number of species across the watershed-level estimates).

• *Determine whether there is additional (more recent) fish tissue data for key states including Pennsylvania, New Jersey, Kentucky and Illinois where U.S. EGUs Hg deposition may be more significant.* We expanded the fish tissue dataset by incorporating additional fish tissue data from the National Listing of Fish Advisories (NLFA), which included additional data for four states (MI, NJ, PA, and MN). We also obtained additional data for Wisconsin. These additional data expanded the number of watersheds in the analysis from 2,317 to 3,141, an increase of 36 percent. The additional watersheds improve coverage in areas with high levels of U.S. EGU-attributable Hg deposition, and thus increase our confidence in the overall results of the Hg Risk TSD.

• *Include additional discussion of the potential that the low sampling rates reflected across many of the watersheds may low-bias the 75th percentile fish tissue Hg estimates used in estimating potential exposures. In addition, include a sensitivity analysis using the 50th percentile estimates to provide a bound on the risk.* The SAB expressed support for the use of the 75th percentile fish tissue Hg value in the Hg Risk TSD, while recommending additional discussion of the issue. We provided additional description of the fish tissue dataset, including distribution of sample sizes and fish species across the watersheds, and an improved discussion of uncertainty and potential low bias resulting from estimation of the 75th percentile fish tissue levels. We also included a sensitivity analysis that used the 50th percentile watershed-level fish tissue Hg level. This sensitivity analysis showed that using the 50th percentile estimates resulted in a decrease in the number and percentage of modeled watersheds with populations potentially at-risk from U.S. EGU-attributable MeHg exposures, from 29 percent of watersheds exceeding either risk metric (*i.e.,* MeHg exposure from U.S. EGUs alone exceeds the RfD or total MeHg exposure exceeds the RfD and U.S. EGUs contribute at least 5 percent) in the revised Hg Risk TSD to 26 percent in the sensitivity analysis in the revised Hg Risk TSD.

• *Expand the discussion of caveats associated with the fish consumption rates used in the analysis.* The SAB was generally supportive of the consumption rates used, while recommending additional discussion of caveats. We expanded the discussion of uncertainty related to the fish consumption rates to address the caveats identified by the SAB. The uncertainty discussion now explains (1) that high-end consumption rates for South Carolina reflect small sample sizes, and therefore may be more uncertain, (2) that the consumption surveys underlying the studies are older (*i.e.,* mostly based on survey data from the 1990s) and behavior may have changed (*i.e.,* consumption rates may have changed since the surveys were conducted), and (3) that consumption rates used in the Hg Risk TSD are annualized rather than seasonal rates and thus contribute little to overall uncertainty. None of these sources of uncertainty is associated with a particular directional bias (*e.g.,* neither systematically higher nor lower risk).

• *Verify whether the consumption rates are daily values expressed as annual averages and whether they are ''as caught'' or ''as prepared.''* We carefully reviewed the studies underlying the fish consumption rates used in the Hg Risk TSD and verified that the rates are annual averages of the daily consumption rates and that they represent as prepared estimates. We also expanded the explanation of the exposure calculations to describe more completely the exposure factors and equation used to generate the average daily MeHg intake estimates for the subsistence scenarios.

• *Explain the criteria for exclusion of fish less than 7 inches in length from analysis.* We provided the rationale for the 7-inch cutoff for edible fish used in the Hg Risk TSD. Seven inches represents a minimum size limit for a number of key edible freshwater fish species established at the state level. For example, Pennsylvania establishes 7 inches as the minimum size limit for both trout and salmon (other edible fish species such as bass, walleye and northern pike have higher minimum size limits). The impact of the 7-inch cutoff is likely to be quite small, as only 6 percent of potential fish samples were excluded due to this criterion.

• *Identify the number of watersheds excluded from the analysis due to the criterion for excluding watersheds with less than 25 members of a source population.* The SAB was generally supportive of the approach used for identifying watersheds with the potential for subsistence activity, while recommending additional information on the results of applying the approach. We added a figure to illustrate the number of watersheds with fish tissue Hg data used to model risk for each of the subsistence fishing scenarios. For all scenarios except the female subsistence fishing scenario, the exposure scenarios significantly limited the number of

[29] As stated in the preamble to the proposal, based on the current literature, exposures above the RfD contribute to risk of adverse effects.

[30] See the literature summary in Chapter 4 of U.S. EPA. 2000. *Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories.* Office of Science and Technology, Office of Water, Washington, DC EPA 823–B–00–007.

[31] In the Hg Risk TSD accompanying the proposed rule, we assumed that 100 percent of Hg in fish was MeHg. We derived the 0.95 conversion factor for the revised Hg Risk TSD to reflect that most studies show that more than 90 percent of total Hg in fish is MeHg. See Chapter 4 of U.S. EPA, 2000.

watersheds. Because the female subsistence fishing scenario does not differentiate with regard to ethnicity or socio-economic status (SES), we applied this scenario to all regions of the country and to all watersheds with fish tissue Hg data. This reflects our assumption that, given the generalized nature of the female subsistence fishing scenario, it is reasonable to assume that it could potentially occur at any watershed with fish tissue Hg data. The female subsistence fishing scenario included in the revised risk assessment is similar to the high-consuming female scenario included in the Hg Risk TSD.[32] However, the female subsistence fishing scenario is applied to all watersheds, while in the scenario for the high-consuming low-income female angler, we only evaluated watersheds with a population of at least 25 low-income females. The female subsistence fishing scenario provides greater coverage geographically than the high-consuming low-income female scenario. As described in the revised Hg Risk TSD, the EPA made this change in response to SAB's concerns regarding the potential exclusion of watersheds with fewer than 25 individuals and regarding coverage for high-end recreational fish consumption.[33]

• *Enhance the discussion of the assumption of a linear relationship between changes in Hg deposition and changes in fish tissue Hg at the watershed level, including providing citations to more recent studies supporting the proportional relationship between changes in Hg deposition and changes in MeHg fish tissue levels.* The SAB supported the assumption of a linear relationship between changes in Hg deposition and changes in fish tissue Hg at the watershed level, while recommending additional supporting language. We expanded our discussion of the scientific basis for the proportionality assumption and added citations for the more recent studies supporting the assumption. We also expanded the discussion of uncertainties associated with this assumption, including uncertainties related to the potential for sampled fish tissue Hg level to reflect previous Hg deposition, and the potential for non-air sources of Hg to contribute to sampled fish tissue Hg levels. Each of these sources of uncertainty may result in potential bias in the estimate of exposure associated with current deposition. If the fish tissue Hg levels are too high due to either previous Hg deposition or non-air sources of Hg, then the absolute level of exposure attributed to both total Hg deposition and U.S. EGU-attributable Hg deposition will be biased high. However, the percent contribution from U.S. EGUs will not be affected as it depends entirely on deposition. The EPA took steps to minimize the potential for these biases by (1) only using fish tissue Hg samples from after 1999, and (2) screening out watersheds that either contained active gold mines or had other substantial non-U.S. EGU anthropogenic emissions of Hg. The SAB concluded that the EPA's approach to minimizing the potential for these biases to affect the results of the Hg Risk TSD is sound. In addition, we conducted several sensitivity analyses to gauge the impact of excluding watersheds with the potential for non-EGU Hg loading. We found that the estimates of the percent of modeled watersheds with populations potentially at-risk were largely insensitive to these exclusions, suggesting that any potential biases from including watersheds with potential non-air Hg loadings are likely to be small.

• *Additional sources of variability should be discussed in terms of the degree to which they are reflected in the design of the risk assessment and the impact that they might have on risk estimates. These include: (1) The geographic patterns of populations of subsistence fishers, including how this factor interacts with the limited coverage we have for watersheds with our fish tissue Hg data, (2) the protocols used by states in collecting fish tissue Hg data, (3) body weights for subsistence fishing populations and the impact that this might have on exposure estimates, and (4) preparation and cooking methods which affect the conversion of fish tissue Hg levels (as measured) into ''as consumed'' values.* We expanded the discussion of sources of variability in the revised Hg Risk TSD to more fully address these sources of variability. The Hg Risk TSD quantitatively reflected many aspects of variability, including spatial and temporal variability in Hg emissions, Hg deposition, fish tissue Hg levels, and subsistence behavior. After evaluating the aspects of variability assessed qualitatively in the Hg Risk TSD such as temporal response in fish tissue, we do not believe that quantitatively incorporating any of these aspects would substantially change the risk results given the stated goal of the analysis to identify watersheds where potential exposures to MeHg from self-caught fish consumption could exceed the RfD.

• *Additional sources of uncertainty should be discussed in terms of their potential impact on risk estimates. These include: (1) Emissions inventory used in projecting total and U.S. EGU-attributable Hg deposition, including the projection of reductions in U.S. EGU emissions for the 2016 scenario, (2) air quality modeling with CMAQ including the prediction of future air quality scenarios, (3) ability of the Mercury Maps-based approach for relating Hg deposition to MeHg in fish to capture Hg hotspots, (4) the limited coverage that we have with fish tissue Hg data for watersheds in the U.S. and implications for the Hg Risk TSD, (5) the preparation factor used to estimate ''as consumed'' fish tissue Hg levels, (6) the proportionality assumption used to relate changes in Hg deposition to changes in fish tissue Hg levels at the watershed-level, (7) characterization of the spatial location of subsistence fisher populations (including the degree to which these provide coverage for high-consuming recreational fishers), and (8) application of the RfD to low SES populations and concerns that this could low-bias the risk estimates.* We expanded the discussion of sources of uncertainty presented in the revised TSD to address more fully these sources of uncertainty and the potential impact on risk estimates. Regarding these eight additional sources of uncertainty, we have (1) evaluated the uncertainties in the emissions and determined that while an important source of uncertainty, we are not able to quantify emissions uncertainty in the risk analysis, but have determined that the emissions inventories and emissions models represent the best available methods for predicting Hg emissions in the U.S., (2) evaluated the uncertainties in the Hg deposition predictions and determined that while an important source of uncertainty, we are not able to quantify uncertainty in Hg deposition in the Hg Risk TSD. Moreover, the CMAQ model used to estimate deposition is based on peer reviewed science and represents the best available method for predicting Hg deposition in the U.S., (3) evaluated the ability of the Mercury Maps-based approach for relating Hg deposition to MeHg in fish to capture Hg hotspots and determined that while finer resolution deposition modeling might reveal additional areas with elevated deposition, the 12 kilometer

32 In the Revised Hg Risk TSD, this population is also referred to as the ''typical female subsistence consumer.''

33 This change led to a very small increase in the number of watersheds with populations potentially at-risk. In the Hg Risk TSD accompanying the proposed rule, approximately 4 percent of modeled watersheds were excluded based on the SES-based filtering criteria.

(km) deposition modeling matches well with the watershed size selected for the analysis, and thus the use of 12 km deposition estimates with the Mercury Maps based approach will not be a large source of uncertainty, (4) evaluated the limited coverage that we have with fish tissue Hg data for watersheds in the U.S. and implications for the Hg Risk TSD and based on the SAB's recommendations, we supplemented the coverage of watersheds by obtaining additional fish tissue Hg samples for areas heavily impacted by U.S. EGU deposition, thus reducing the uncertainty in the analysis, (5) evaluated the uncertainty in the preparation factor and determined that the level of uncertainty is low, and as such would have minimal impact on the risk estimates, (6) evaluated the uncertainty resulting from the proportionality assumption used to relate changes in Hg deposition to changes in fish tissue Hg levels at the watershed-level, and determined, based both on quantitative sensitivity analyses and qualitative assessments, that this source of uncertainty is not likely to greatly influence the results, and is not likely to have a specific directional bias, (7) evaluated the uncertainty related to characterization of the spatial locations of subsistence populations and determined that uncertainty could be reduced by focusing the risk estimates on female subsistence fishing populations, which are assumed to have the potential to fish in all watersheds, in response to SAB's concerns regarding potential exclusion of watersheds with fewer than 25 individuals and (8) evaluated the potential impact of the uncertainty in application of the RfD to low SES populations. The EPA determined that due to the method used in calculating the RfD, we have confidence that the RfD provides protection for low SES populations.

- *Expand the sensitivity analyses (over those included in the original risk assessment) to address uncertainty related to the use of the 75th percentile fish tissue Hg value (at each watershed) as the core risk estimate.* Based on the SAB's recommendation, we added a sensitivity analysis using the median fish tissue Hg estimate (at the watershed level). This sensitivity analysis showed that use of the median fish tissue Hg concentration instead of the 75th percentile resulted in a relatively small decrease (*i.e.,* 10 percent) in the estimates of watersheds with populations potentially at-risk, and did not substantially change the conclusions of the risk assessment.

C. Summary of Results of Revised Hg Risk TSD of Risks to Populations With High Levels of Self-Caught Fish Consumption

Based on the recommendations we received from the SAB, we revised the quantitative analysis of risk to subsistence fishing populations with high levels of fish consumption. Our revision to the quantitative risk results reflects three key recommendations from the SAB, including (1) addition of 824 watersheds based on additional fish tissue Hg sample data we obtained from states and the National Listing of Fish Advisories, (2) application of a 0.95 adjustment factor to the reported fish tissue Hg concentrations to account for the fraction that is MeHg, and (3) inclusion of all watersheds with fish samples that meet the filtering criteria [34] in representing potential exposures associated with increased risk of neurologic health effects for female subsistence fishing populations.

Based on these revisions, our estimates of the number and percent of modeled watersheds with populations potentially at-risk from exposure to EGU-attributable MeHg changed from those presented in the preamble to the proposed rule.[35] For the 99th percentile consumption scenario, the number of watersheds with fish tissue Hg samples where subsistence fishing populations may be at-risk from exposure to EGU-attributable MeHg increased from 672 to 917 (an increase of 36 percent). For this same scenario, the total percent of modeled watersheds with populations potentially at-risk from either risk metric (*i.e.,* MeHg exposure from U.S. EGUs alone exceeds the RfD or total MeHg exposure exceeds the RfD and U.S. EGUs contribute at least 5 percent) increased from 28 percent estimated at proposal to 29 percent after addressing SAB recommendations. The increase in the total percent of modeled watersheds with populations potentially at-risk using the expanded geographic coverage of watersheds provides additional confidence that emissions of Hg from U.S. EGUs pose a hazard to public health. For the 99th percentile consumption scenario, the percent of modeled watersheds with populations potentially at-risk from total potential exposures to MeHg that exceed the RfD and U.S. EGUs contribute at least 5 percent increased from 22 percent to 24 percent. For the 99th percentile consumption scenario, the percent of modeled watersheds with populations potentially at-risk based on Hg deposition from U.S. EGUs alone decreased from 12 percent to 10 percent.

The additional sensitivity analyses conducted in response to the SAB peer review showed that the estimates of the percent of modeled watersheds with populations potentially at-risk are robust to alternative assumptions about both the watersheds included in the analysis and the selection of the 50th percentile or 75th percentile fish tissue Hg level. Sensitivity analyses excluding entire states with the potential for historical loadings of Hg from non-air sources [36] resulted in an increase from 29 percent to 33 percent in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric (*i.e.,* U.S. EGUs alone or total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent). Including only watersheds in the top 25th percentile of U.S. EGU deposition resulted in an increase in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric, from 29 percent to 30 percent. Using the 50th percentile fish tissue Hg level resulted in a decrease in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric, from 29 percent to 26 percent. On balance, these sensitivity analyses do not substantially reduce the percent of modeled watersheds with populations potentially at-risk, and thus confirm the finding that Hg emissions from U.S. EGUs pose a hazard to public health. In fact, given the broader coverage of modeled watersheds in the revised analysis, we have even greater confidence in our finding that Hg

[34] The watersheds were filtered to exclude watersheds that: (a) Were not freshwater, (b) did not have fish sampling data since 2000, (c) did not have fish larger than 7 inches in length, (d) contained active gold mines or (e) had substantial non-air Hg loading.

[35] Since the time of the analyses conducted in support of the proposed rule, the EPA updated IPM modeling to reflect the most recently available information, including public comments and the final CSAPR (see IPM Documentation for further details on these updates, which is available in the docket). Compared to the modeling conducted at proposal, these updates are projected to result in greater reductions in criteria pollutants, and also to have a slightly greater impact on U.S. EGU Hg emissions. Based on the revised projection for 2016, the EPA estimates that U.S. EGUs would emit 27 tons of Hg, as compared to the 29 tons we modeled for the Hg Risk TSD. We do not expect this 2 ton difference to substantially change the mercury risks reported in the preamble to the proposed rule, as this represents less than a 10 percent reduction in Hg emissions.

[36] The SAB noted that areas with substantially elevated fish tissue Hg levels could also be characterized by lakes and rivers with high natural methylation rates, and thus some of the states we excluded for this sensitivity analysis might not have fish tissue Hg levels that reflect non-U.S. EGU Hg loadings.

emissions from U.S. EGUs pose a hazard to public health.

D. Peer Review of the Approach for Estimating Cancer Risks Associated With Cr and Ni Emissions in the U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP and EPA Response

As explained in the preamble to the proposed rule, the EPA submitted for peer review its characterization of the chemical speciation for the emissions of Cr and Ni used in the non-Hg HAP inhalation risk case studies. The remaining aspects of the non-Hg HAP case study risk assessments used methods that were previously peer reviewed. Specifically, the methodologies used to conduct the non-Hg case studies are consistent with those used to conduct inhalation risk assessments under EPA's Risk and Technology Review (RTR) program. Because the RTR assessments are considered to be highly influential science assessments, the methodologies used to conduct them were subject to a peer review by the SAB in 2009. The SAB issued its peer review report in May 2010.[37] The report endorsed the risk assessment methodologies used in the program, and made a number of technical recommendations for EPA to consider as the RTR program evolves.

The EPA's case studies identified Cr and Ni emissions as the key drivers of the estimated inhalation cancer risks for EGUs. Because these results hinged on specific scientific interpretations of data used to characterize EGU emissions of Cr and Ni, the EPA conducted a letter peer review of its analysis and interpretation of those data relative to the quantification of inhalation risks associated with Cr and Ni emissions from U.S. EGUs. The following sections describe the peer review process, enumerate the peer review charge questions presented to the peer review panel, summarize the key recommendations from the peer review, and summarize our responses to those recommendations.

1. Summary of Peer Review Process

The EPA asked three independent, external peer reviewers representing government, academic and the private sector to review of the methods for developing inhalation cancer risk estimates associated with emissions of Cr and Ni compounds from coal- and oil-fired EGUs in support of the appropriate and necessary finding. The approaches and rationale for the technical and scientific considerations used to derive inhalation cancer risks were summarized in the draft document entitled, ''Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds.'' The peer reviewers received several charge questions (three questions on Cr and two questions on Ni, which are provided below) on the technical and scientific relevance of the approaches used to develop the inhalation unit risk estimates. The EPA also provided information on Cr speciation profiles for different industrial sources, as well as information on the Ni speciation of PM from oil-fired EGUs.

2. Peer Review Charge Questions

Below, we present the charge questions posed to the peer reviewers to help guide their review and development of recommendations to EPA on key issues relevant to the characterization of risks from EGU emissions containing either Cr or Ni compounds.

The EPA asked three questions regarding Cr and Cr compounds:

Question 1: Do EPA's judgments related to speciated Cr emissions adequately take into account the available Cr speciation data?

Question 2: Has EPA selected the species of Cr (*i.e.,* hexavalent Cr, Cr(VI)) that accurately represents the toxicity of Cr and Cr compounds?

Question 3: Are the assumptions used in past analysis scientifically defensible, and are there alternatives that EPA should consider for future analysis?

The EPA asked two questions regarding Ni and Ni compounds:

Question 1: Do EPA's judgments related to speciated Ni emissions adequately take into account available speciation data, including recent industry spectrometry studies?

Question 2: Based on the speciation information available and on what we know about the health effects of Ni and Ni compounds, and taking into account the existing Unit Risk Estimates (URE) values (*i.e.,* values derived for EPA's Integrated Risk Information System (IRIS), California Environmental Protection Agency (Cal EPA) and Texas Commission on Environmental Quality (TCEQ)), the EPA has provided several approaches[38] to derive unit risk estimates that may be more scientifically defensible than those used in past analyses. Which of the options presented would result in more accurate and defensible characterization of risks from exposure to Ni and Ni compounds? Are there alternative approaches that EPA should consider?

3. Summary of Peer Review Findings and Recommendations

Regarding Cr and Cr compounds, all three reviewers considered Cr(VI) as the species likely to be driving cancer risks based on solid evidence from the health effects database for Cr and Cr compounds. All three authors also considered EPA's use of the average of the range of the available speciation data (*i.e.,* 12 percent and 18 percent Cr(VI) contained in coal- and oil-fired EGUs, respectively) as a reasonable approach for the derivation of default speciation profiles to be used when there is no speciation data available. All reviewers agreed that there is high uncertainty associated with the variability in the speciation data available for Cr (*e.g.,* range of approximately 4 to 23 percent Cr(VI) from coal-fired units). One of the reviewers recommended several additional studies for EPA's consideration; the EPA considered these in finalizing the report.

Regarding Ni and Ni compounds, the reviewers agreed with the views of the international scientific bodies, which consider Ni compounds carcinogenic as a group. One reviewer recommended that the EPA review several additional Ni speciation data that suggests that sulfidic Ni compounds (which the reviewer considered as the most potent carcinogens within the group of all Ni compounds) are present at low levels in emissions from EGUs. In addition, this reviewer pointed out that there is a recently proposed model that may explain the differences in carcinogenic potential across Ni compounds.

4. The EPA's Responses to Peer Review Recommendations

We summarize EPA's basic responses to the peer review comments below, first for Cr-related issues, and second for Ni-related issues, which are reflected in the revised document.[39]

[37] U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA–SAB). 2010. *Review of EPA's draft entitled, ''Risk and Technology Review (RTR) Risk Assessment Methodologies: For Review by the EPA's Science Advisory Board with Case Studies—MACT I Petroleum Refining Sources and Portland Cement Manufacturing''. EPA–SAB–10–007. May. Available on-line at: http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf.*

[38] See section 3.3 of U.S. Environmental Protection Agency (U.S. EPA). 2011c. *Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds.* Office of Air Quality Planning and Standards. October.

[39] U.S. EPA, 2011c.

a. Cr and Cr Compounds

In agreement with the peer reviewers and based on the health effects information available for Cr, the EPA assigns high confidence in the assumption that Cr(VI) is the carcinogenic species driving the risk of Cr-emitting facilities. In agreement with the reviews, the EPA considers derivation of default speciation profiles based on the mass of Cr(VI) a reasonable approach. As suggested by one of the reviewers, the EPA reviewed two potentially relevant studies, one of which showed coal combustion emissions containing as much as 43 percent Cr(VI),[40] which suggests that the EPA's quantitative approach could actually underestimate Cr(VI) inhalation risks. However, the other study reviewed by EPA on speciation of Cr in coal combustion showed Cr(VI) percentage levels close to detection limits (*i.e.,* 3 to 5 percent of total Cr, which was close to the limit of detection in this study).[41] Thus, the more recent speciation data available is unlikely to reduce the uncertainty of the Cr speciation analyses used by EPA as the bases for risk characterization analysis.

In agreement with the peer reviewers, the EPA also recognizes that the confidence in the default speciation profiles is low because the profiles are based on a limited data set with a wide range of percentages of Cr(VI) across the different samples.

b. Ni and Ni Compounds

Based on the views of the major scientific bodies mentioned above and the peer reviewers that commented on EPA's approaches to risk characterization of Ni compounds, the EPA considers all Ni compounds to be carcinogenic as a group and the EPA does not consider Ni speciation or Ni solubility to be strong determinants of Ni carcinogenicity. These scientific bodies also recognize that based on the data available, the precise Ni compound(s) responsible for the carcinogenic effects in humans is not always clear, and that there may be differences in the potential toxicity and carcinogenic potential across Ni compounds. Nevertheless, studies in humans indicate that various mixtures of Ni compounds (including Ni sulfate, sulfides and oxides, alone or in combination) encountered in the Ni refining industries may cause cancer in humans, and there is no reason to expect anything different from this for mixtures of Ni compounds from other emission sources. One of the reviewers suggested we consider views by some authors that believe that water soluble Ni, such as Ni sulfate, should not be considered a human carcinogen. This view is based primarily on a negative Ni sulfate 2-year rodent bioassay by the National Toxicology Program (NTP) (which is different from the positive 2-year NTP bioassay for Ni subsulfide).[42 43 44] One review article identifies the discrepancies between the animal and human data (*i.e.,* from studies of cancers in workers inhaling certain forms of Ni versus inhalation studies suggesting different carcinogenic potential in rodents with different Ni compounds) and states that the epidemiological data available clearly support an association between Ni and increased cancer risk, although the article acknowledges that the data are weakest regarding water soluble Ni. In addition, the EPA identified a recent review[45] that highlights the robustness and consistency of the epidemiological evidence across several decades showing associations between exposure to Ni and Ni compounds (including Ni sulfate) and cancer.

Regarding the second charge question on Ni compounds, two reviewers suggested using the URE derived by the TCEQ[46] for all Ni compounds as a group, rather than the one derived by the Integrated Risk Information System (IRIS, 1991)[47] specifically for Ni subsulfide. The third reviewer did not comment on an alternative approach. Considering this, to develop our primary risk estimate, the EPA decided to use a health protective approach by applying 100 percent of the current IRIS URE for Ni subsulfide, rather than assuming that 65 percent of the total mass of emitted Ni might be Ni subsulfide, as used in previous analyses. We used the IRIS URE value because IRIS values are preferred given the conceptual consistency with EPA risk assessment guidelines and the level of peer review that such values receive. We used 100 percent of the IRIS value because of the concerns about the potential carcinogenicity of all forms of Ni raised by the major national and international scientific bodies, and recommendations of the peer reviewers. Nevertheless, taking into account that there are potential differences in toxicity and/or carcinogenic potential across the different Ni compounds, and given that two URE values have been derived for exposure to mixtures of Ni compounds that are two to three fold lower than the IRIS URE for Ni subsulfide, the EPA also considers it reasonable to use a value that is 50 percent of the IRIS URE for Ni subsulfide for providing an estimate of the lower end of a plausible range of cancer potency values for different mixtures of Ni compounds.

Although this report focused primarily on cancer risks associated with emissions containing Ni compounds, it is important to note that comparative quantitative analyses of non-cancer toxicity of Ni compounds indicate that Ni sulfate is as toxic or more toxic than Ni subsulfide or Ni oxide which does not support the notion that the solubility of Ni compounds is a strong determinant of its toxicity.[48 49]

E. Summary of Results of Revised U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP

Based on the results of the peer review and public comments on the non-Hg case study chronic inhalation risk assessment, we made several changes to the emissions estimates, dispersion modeling, and risk characterization for the modeled case study facilities. Key changes include (1) changes in emissions, (2) changes in stack parameters for some facilities based on new data received during the

[40] Galbreath KC, Zygarlicke CJ. 2004. ''Formation and chemical speciation of arsenic-, chromium-, and nickel-bearing coal combustion $PM_{2.5}$,'' *Fuel Process Technol* 85:701–726.

[41] Huggins FE, Najih M, Huffman GP. 1999. ''Direct speciation of chromium in coal combustion by-products by X-ray absorption fine structure spectroscopy,'' *Fuel Process Techno*l 78:233–242.

[42] Oller A. 2002. ''Respiratory carcinogenicity assessment of soluble nickel compounds.'' *Environ Health Perspect.* 110:841–844.

[43] Heller JG, Thornhill PG, Conard BR. 2009. ''New views on the hypothesis of respiratory cancer risk from soluble nickel exposure; and reconsideration of this risk's historical sources in nickel refineries.'' *J Occup Med Toxicol.* 4:23.

[44] Goodman JE, Prueitt RL, Thakali S, and Oller AR. 2011. ''The nickel iron bioavailability model of the carcinogenic potential of nickel-containing substances in the lung.'' *Crit Rev Toxicol* 41:142–174.

[45] Grimsrud TK and Andersen A. ''Evidence of carcinogenicity in humans of water-soluble nickel salts.'' *J Occup Med Toxicol.* 2010. 5:1–7. Available online at *http://www.ossup-med.com/content/5/1/7.*

[46] Texas Commission on Environmental Quality (TCEQ). 2011. *Development Support Document for nickel and inorganic nickel compounds.* Available online at *http://www.tceq.state.tx.us/assets/public/implementation/tox/dsd/final/june11/nickel_&_compounds.pdf.*

[47] U.S. EPA, 1991. *Integrated Risk Information Service (IRIS) assessment for nickel subsulfide.* Available at: *http://www.epa.gov/iris/subst/0273.htm.*

[48] Haber LT, Allen BC, Kimmel CA. 1998. ''Non-Cancer Risk Assessment for Nickel Compounds: Issues Associated with Dose-Response Modeling of Inhalation and Oral Exposures.'' *Toxicol Sci.* 43:213–229.

[49] National Toxicology Program (NTP). 1996. *Technical Report Series No. 454, Toxicology and carcinogenesis studies of nickel sulfate hexahydrate.* July. Available online at *http://ntp.niehs.nih.gov/ntp/htdocs/LT_rpts/tr454.pdf.*

public comment period, (3) use of updated versions of AERMOD and its input processors (AERMAP, AERMINUTE, and AERMET), and (4) use of 100 percent of the current IRIS URE for Ni subsulfide to calculate Ni-associated inhalation cancer risks (rather than assuming that the Ni might be 65 percent as potent as Ni subsulfide).

Based on estimated actual emissions, the highest estimated individual lifetime cancer risk from any of the 16 case study facilities was 20 in a million, driven by Ni emissions from the one case study facility with oil-fired EGUs. Of the facilities with coal-fired EGUs, five facilities had maximum individual cancer risks greater than one in a million [50] (the highest was five in a million), with the risk from four due to emissions of Cr(VI) and the risk from one due to emissions of Ni.[51] There were also two facilities with coal-fired EGUs that had maximum individual cancer risks equal to one in a million. All of the facilities had non-cancer Target Organ Specific Hazard Index (TOSHI) [52] values less than one, with a maximum TOSHI value of 0.4 (also driven by Ni emissions from the one case study facility with oil-fired EGUs).

Since these case studies do not cover all facilities in the category, and since our assessment does not include the potential for impacts from different EGU facilities to overlap one another (*i.e.,* these case studies only look at facilities in isolation), the maximum risk estimates from the case studies likely underestimates true maximum risks for the source category.

Based on the fact that six U.S. EGUs were estimated to meet or exceed the CAA section 112(c)(9) criterion of one in a million, EGUs cannot be removed from the list of source categories to be regulated under CAA section 112.

[50] A risk level of 1 in a million implies a likelihood that up to one person, out of one million equally exposed people would contract cancer if exposed continuously (24 hours per day) to the specific concentration over 70 years (an assumed lifetime). This would be in addition to those cancer cases that would normally occur in an unexposed population of one million people.

[51] When the lower end of the cancer potency range for Ni was used to develop risk estimates, 5 of the 16 facilities had maximum cancer risks exceeding 1 in a million, and the maximum individual cancer risk for any single facility fell to 10 in a million.

[52] The target-organ-specific hazard index (TOSHI) is a metric used to assess whether there is an appreciable risk of deleterious (noncancer) effects to a specific target organ due to continuous inhalation exposures over a lifetime. If a TOSHI value is less than or equal to one, such effects are unlikely. For TOSHI values greater than one, there is an increased risk of such effects.

F. Public Comments and Responses to the Appropriate and Necessary Finding

1. Legal Aspects of Appropriate and Necessary Finding

a. History of Section 112(n)(1)(A)

Comment: One commenter provided a detailed history of EPA's regulatory actions concerning EGUs and implementation of CAA section 112(n)(1)(A). The same commenter implies that the EPA's 2000 appropriate and necessary finding and listing of EGUs was flawed because the Agency did not comply with CAA section 307(d) rulemaking process. The commenter sought review of the 2000 notice in the U.S. Court of Appeals for the District of Columbia Circuit, which was dismissed by the D.C. Circuit. *Utility Air Regulatory Group* v. *EPA,* No. 01–1074 (D.C. Cir. July 26, 2001). The commenter then characterizes at length the 2005 EPA action that revised the interpretation of CAA section 112(n)(1)(A) and, which the D.C. Circuit concluded illegally removed EGUs from the CAA section 112(c) list of sources that must be regulated under CAA section 112. *See New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). The commenter notes that the D.C. Circuit did not rule on the legal correctness or the sufficiency of the factual record supporting EPA's 2000 listing decision or on the factual correctness of EPA's later decision to reverse its CAA section 112(n)(1)(A) determination. The commenter noted further that the D.C. Circuit indicated that the listing decision could be challenged when the Agency issued the final CAA section 112(d) standards pursuant to CAA section 112(e)(4). The commenter concluded by asserting that the Agency could not ignore the history associated with the regulation of EGUs under section 112 and that two earlier dockets—Docket ID. No. A–92–55 and Docket ID. No. EPA–HQ–OAR–2002–0056—are also part of this long rulemaking effort and must be accounted for in conjunction with Docket No. EPA–HQ–OAR–2009–0234 if all pertinent material and comments are to be part of the rulemaking record.

Response: The commenter characterizes the regulatory history of the rule EPA proposed on May 3, 2011. To the extent that characterization is inconsistent with the lengthy regulatory history EPA provided in the preamble to the May 3, 2011 rule, we disagree. We address several of the statements in more detail below.

First, the commenter makes much of the fact that the EPA did not go through CAA section 307(d) notice and comment rulemaking when making the appropriate and necessary finding and listing decision in 2000. However, the commenter's complaint is without foundation. The CAA does not require CAA section 307(d) rulemaking for listing decisions. In fact, CAA section 112(e)(4) specifically provides that listing decisions may only be challenged ''when the Administrator issues emission standards for such * * * [listed] category.'' Second, the commenter challenged the listing decision in the U.S. Court of Appeals for the District of Columbia Circuit (Court) and, on July 26, 2001, the Court granted EPA's motion to dismiss that action based on the plain language of CAA section 112(e)(4). Moreover, in addition to the 2000 notice, the EPA clearly articulated its basis for listing EGUs in this proposed rule, which is consistent with CAA section 307(d), and the commenter was provided an ample opportunity to comment. Finally, the commenter asserts that the rulemaking docket for this action is incomplete because the Agency did not include two earlier dockets—Docket ID. No. A–92–55 and Docket ID. No. EPA–HQ–OAR–2002–0056—for the Section 112(n) Revision Rule, 70 FR 15994 (March 29, 2005), and the reconsideration of the Section 112(n) Revision Rule, 71 FR 33388 (June 9, 2006), respectively. The commenter is incorrect because EPA incorporated by reference the two dockets at issue. *See* EPA–HQ–OAR–2009–0234–3056.

Comment: One commenter stated that the EPA has assessed the public health risks posed by HAP emissions from coal- and oil-fired EGUs for the last 40 years. According to the commenter, throughout that time, the EPA has come to a single repeated conclusion that HAP emissions from EGUs pose little or no risk to public health. Based on this conclusion, the EPA has properly chosen not to require EGUs to install expensive, new pollution control equipment to control HAP emissions. The commenter asserts that, in this proposed rule, the EPA shifts its opinion on the health impacts of EGU HAP emissions 180 degrees and now seeks to impose sweeping regulatory requirements on all power plants. According to the commenter, the EPA's newfound concern about HAP emissions from EGUs is not based on new and different assessments of the public health consequences of EGU HAP emissions but instead on health benefits from the reduction of non-hazardous air pollutants, primarily PM, which the Agency is required to regulate under other provisions of the CAA. One commenter stated that for decades, the EPA set primary ambient air quality standards that protect public health with an adequate margin of safety, CAA section 109(b)(1), and set secondary standards that are [sic] ''requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air,'' CAA 109(b)(2). The commenter notes that even if EPA now views those past PM standards as inadequate, the EPA has ongoing regulatory proceedings in which it can address any perceived health concerns. The commenter concludes that regulation of EGU HAP emissions under CAA section 112 is an unlawful way to address those concerns.

Response: The commenter is incorrect in its assertion that the Agency has consistently concluded that HAP emissions from EGUs do not present a hazard to public health. In the 2000 finding, the Agency concluded that HAP emissions from coal- and oil-fired EGUs do pose a hazard to public health and determined that it was appropriate and necessary to regulate such units under CAA section 112. As a result of that finding, the EPA added coal- and oil-fired EGUs to the CAA section 112(c) list of source categories for which emission standards are to be established pursuant to CAA section 112(d). Further, in support of the proposed rule, the EPA conducted additional extensive quantitative and qualitative analyses, which confirm that it remains appropriate and necessary to regulate EGUs under CAA section 112. Among other things, those analyses demonstrate that emissions from coal- and oil-fired EGUs continue to pose a hazard to public health. The commenter also fails to note that the EPA found that HAP emissions from EGUs pose a hazard to the environment as well.

The commenter seems confused about the basis for the Agency's appropriate and necessary finding because it maintains that the EPA made the appropriate and necessary finding based on the health co-benefits attributable to PM reductions that will be achieved as a result of the Agency's regulation of HAP emissions from EGUs. Nowhere in the May 2011 proposal does EPA state that it based the appropriate and necessary finding on hazards to public health attributable to PM emissions. The commenter's allegation lacks foundation. The appropriate and necessary finding unmistakably focuses on the hazards to public health and hazards to the environment associated with HAP emissions from EGUs.

Comment: One commenter stated that CAA section 112 required EPA to make a risk-based determination in order to regulate HAP. According to the commenter, the EPA may regulate substances ''reasonably * * * anticipated to result in an increase in mortality or increase in serious illness'' to a level that protects public health with an ''ample margin of safety.'' According to the commenter, the EPA has regulated a number of HAP emitted from industrial source categories other than EGUs.

As for EGUs, according to the commenter, the EPA found that the combustion of fossil fuels produces extremely small emissions 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. The commenter stated that the EPA, in past reviews, found that these HAP emissions did not pose hazards to public health. *See* 48 FR 15076, 15085 (1983) (radionuclides). the commenter further stated that ''[i]n the case of Hg specifically, the EPA found that ''coal-fired power plants * * * do not emit mercury in such quantities that they are likely to cause ambient mercury concentration to exceed'' a level that ''will protect public health with an ample margin of safety.'' 40 FR 48297–98 (October 19, 1975) (Hg); 52 FR 8724, 8725 (March. 19, 1987) (reaffirming Hg conclusion).

According to the commenter, in the late 1980s, the EPA was concerned that its prior risk assessments of individual HAP emissions from fossil-fuel-fired power plants may not reflect the total risks posed by all HAP emitted by those sources. The commenter states that the EPA modeled the risks posed by all HAP emitted by power plants (very much like the analyses the Agency would conduct for the Utility Study ten years later). The commenter asserts that the modeling again failed to identify threats to public health that warranted regulation under an ''ample margin of safety'' test.

Response: The commenter's statements concerning the pre-1990 CAA are not relevant to the current action. Congress enacted CAA section 112(n)(1) as part of the 1990 amendments to the Act. That provision requires, among other things, that the Agency evaluate the hazards to public health posed by HAP emissions from fossil-fuel fired EGUs. Had Congress concluded, as commenter appears to assert, that HAP emissions from EGUs did not pose a hazard to public health or the environment, it defies reason that Congress would have required EPA to conduct the three studies at issue in CAA section 112(n)(1) (titled ''Electric utility steam generating units'') and regulate EGUs under section 112 if the Administrator determined in her discretion that it was appropriate and necessary to do so. The Agency complied with the statutory mandates in CAA section 112(n)(1) in conducting the studies and reasonably exercised its discretion in making the appropriate and necessary finding.

We acknowledge that Congress treated radionuclide emissions from EGUs differently. For radionuclides from EGUs (and certain other sources), Congress included CAA section 112(q)(3), which authorizes but does not require the Agency to maintain the regulations of radionuclides in effect prior to the 1990 amendments. The fact that Congress made an exception for radionuclides and no other HAP from EGUs further demonstrates that the HAP-related actions EPA took with regard to EGUs prior to the 1990 amendments to the CAA are not germane.

As for the commenter's statements about Hg emissions from EGUs, we find their conclusions wholly inconsistent with CAA section 112(n)(1). That provision is titled ''Electric utility steam generating units,'' and it directs EPA to conduct two Hg-specific studies. *See* CAA sections 112(n)(1)(B) and 112(n)(1)(C). The commenter's suggestion that the EPA could or should rely on assessments of Hg from EGUs conducted prior to the 1990 amendments is not tenable.

Finally, the commenter stated that the EPA conducted a risk assessment of all HAP from EGUs prior to the 1990 amendments and that the Agency did not identify any HAP that failed the ''ample margin of safety'' test. The commenter did not cite the study or provide any information to support the statements so we are unable to respond to the alleged study directly; however, the risk assessments conducted in support of the appropriate and necessary finding, as well as the 2000 finding, demonstrate that HAP emissions from EGUs pose hazards to public health and the environment.

b. Interpretation of ''Appropriate'' and ''Necessary''

Comment: One commenter stated that in the preamble to the proposed rule, the EPA sets out its ''interpretation of the critical terms in CAA section 112(n)(1),'' arguing that this latest interpretation is ''wholly consistent with the CAA'' and with the Agency's earlier ''2000 finding.'' *See* 76 FR 24976, 24986 (May 3, 2011). The commenter stated that throughout the proposal EPA tries to suggest that it is returning to some earlier, ''correct'' interpretation of CAA section 112(n)(1) set forth in its 2000 action. *See, e.g.,* 76 FR 24989 (''The Agency's interpretation of the term 'appropriate' * * * is wholly consistent with the Agency's appropriate finding in 2000''); id. at 24992 (''Our interpretation of the necessary finding is reasonable and consistent with the 2000 finding''). According to the commenter, the EPA did not provide in 2000 any interpretation of what it now characterizes as the ''critical terms'' of section 112(n)(1). *See, e.g.,* 70 FR 15999 n.13 (the ''2000 finding does not provide an interpretation of the phrase 'after imposition of the requirements of the Act' ''); id. at 16000/2 (in 2000, the EPA ''did not provide an interpretation of the term 'appropriate' ''); 76 FR 24992 (the ''Agency did not expressly interpret the term necessary in the 2000 finding''). The commenter believes that for that reason alone, it is impossible to credit EPA's assertion that it ''appropriately concluded that it was appropriate and necessary to regulate hazardous air pollutants * * * from EGUs'' in 2000, and that it is today merely ''confirm[ing] that finding and conclud[ing] that it remains appropriate and necessary to regulate these emissions.* * *'' [53]

Response: The commenter disagrees with certain statements in the preamble to the proposed rule that provide that the Agency's interpretation of CAA section 112(n)(1) is reasonable and consistent with the 2000 finding. It is difficult to decipher the exact complaint that the commenter has with EPA's proposed rule in this regard, but the commenter does assert that ''the Agency did not provide in 2000 any interpretation of what it now characterizes as the ''critical terms'' of CAA section 112(n)(1).'' The commenter's assertion lacks foundation. Although the 2000 finding did not provide detailed interpretations of the regulatory terms at issue, it discussed the types of considerations relevant to the appropriate and necessary inquiry. For example, it is clear that in 2000, the Agency was concerned with the then current hazards to public health and the environment when assessing whether it was appropriate to regulate EGUs under section 112.[54] In addition, when evaluating whether it was necessary to regulate utilities, the Agency stated that it was necessary to regulate HAP emissions from U.S. EGUs under section 112 because the implementation of the other requirements of the Act would not adequately address the serious public health and environmental hazards arising from HAP emissions from EGUs. The Agency also specifically noted that ''section 112 is the authority intended to address'' hazards to public health and the environment posed by HAP emissions. *Id.*

The detailed interpretation set forth in the preamble to the proposed rule is consistent with the 2000 finding, but EPA does not assert that the interpretation is in any way necessary to support the factual conclusions reached in the 2000 finding. Instead, we noted in the preamble to the proposed rule that our interpretation is consistent with the 2000 finding because in 2005 we interpreted the statute in a manner that was not consistent with the 2000 finding. The commenter has provided no legal support for its position that the Agency erred in interpreting the statute in a manner that is consistent with a prior factual finding.

Comment: Several commenters assert that in the 1990 amendments to the Clean Air Act, Congress directed the EPA to base its determination regarding regulation of fossil-fuel-fired generating units on consideration of any adverse public health effects identified in the study mandated by the first sentence of section 112(n)(1)(A) and that Congress did not dictate in section 112(n)(1)(A) that the EPA must regulate electric utility steam generating units under section 112.

According to the commenters the sponsor of the House bill that became section 112(n)(1)(A) provides an explanation that contradicts the EPA's approach to regulating EGUs:

> 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, * * * 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.

136 Cong. Rec. H12,934 (daily ed. Oct. 26, 1990) (statement of Rep. Michael Oxley).

The commenters stated that the EPA position is premised on the assumption that ''regulation under section 112'' necessarily means ''regulation under 112(d)'' and falsely premised on the assumption that source categories listed by operation of section 112(n)(1)(A) cannot be regulated differently. The commenters conclude that the language of section 112(n)(1)(a) reflects Congress' intent that ''regulation of HAP from EGUs was not intended to operate under section 112(d) but was instead intended to be tailored to the findings of the utility study mandated by section 112(n)(1)(A).''

Response: The commenters maintain that the Agency's interpretation of CAA section 112(n)(1) is flawed in many respects. The primary support for one commenter's arguments against EPA's interpretation, including in the comment above, is legislative history in the form of statements from one Congressman, Representative Oxley. The Supreme Court has repeatedly stated that the statements of one legislator alone should not be given much weight. *See Brock* v. *Pierce County,* 476 U.S. 253, 263 (1986) (finding that ''statements by individual legislators should not be given controlling effect, but *when they are consistent with the statutory language and other legislative history, they provide evidence of Congress' intent.''*) (*emphasis added*) (citation omitted); *Garcia, et al.,* v. *U.S.,* 469 U.S. 70, 78 (1984), citing *Zuber* v. *Allen,* 396 U.S. 168, 187 (1969) (reiterating its prior findings, the Court indicated that isolated statements ''are 'not impressive legislative history.' ''); *Weinberger, et al.,* v. *Rossi et al.,* 456 U.S. 25, 35 (declining to make a ruling based on ''one isolated remark by a single Senator''); *Consumer Product Safety Comm., et al.* v. *GTE Sylvania, Inc., et al.,* 447 U.S. 102, 117–118 (1980) (declining to give much weight to isolated remarks of one Representative); *Chrysler Corp.* v. *Brown, et al.,* 441 U.S. 281, 311 (1979) (finding that ''[t]he remarks of a single legislator, even the sponsor, are not controlling in analyzing legislative history.''); *Zuber,* 396 U.S. at 186 (concluding that ''[f]loor debates reflect at best the understanding of individual Congressmen.''); and *U.S.* v. *O'Brien,* 391 U.S. 367, 384 (1968) (in evaluating the statements of a handful of Congressmen, the Court concluded that ''[w]hat motivates one legislator to make a speech about a statute is not necessarily what motivates scores of others to enact it. * * *.''). As these cases show, the Supreme Court does not give weight to the statements of an individual legislator, except when the statements are supported by other legislative history and the clear intent of the statute. The commenters cited no case law that would support reliance on such limited legislative history.

The commenter has not cited any other legislative history to support

[53] *Id.* at 24,977/3.

[54] 65 FR 79830.

Representative Oxley's statement, and the lack of additional support makes the statement of little utility or import under the case law. In fact, there does not appear to be anything in the House, Senate, or Committee Reports that supports Oxley's statement. The lack of support for Oxley's statement in the Committee Report is particularly telling since, as the commenter notes, the House and Senate bills required different approaches to regulating EGUs under section 112, with the Senate bill requiring EGUs be regulated prior to the Utility Study. In fact, legislative statements from Senator Durenberger, a supporter of the Senate version, demonstrate that others would almost certainly not have agreed with Oxley's interpretation. For example, Senator Durenberger stated, ''It seems to me inequitable to impose a regulatory regime on every industry in America and then exempt one category, especially a category like power plants which are a significant part of the air toxics problem.''

Senator Durenberger discussed the negotiations with the Administration and the industry push to avoid regulation, including industry arguments for not regulating Hg from U.S. EGUs:

> The utility industry continued to adamantly oppose [regulation under section 112]. First, they argued that mercury isn't much of an environmental problem. But as the evidence mounted over the summer and it became clear that mercury is a substantial threat to the health of our lakes, rivers and estuaries and that power plants are among the principal culprits, they changed their tactic. Now they are arguing that mercury is a global problem so severe that just cleaning up U.S. power plants won't make enough of a difference to be worth it. They've gone from 'we're not a problem' to 'you can't regulate us until you address the whole global problem.' Recasting an issue that way is not new around here. So, it is not a surprise. But it does suggest the direction in which this debate will be heading in the next few years.

136 Cong. Rec. 36062 (October 27, 1990).

Senator Durenberger also explained why the House version was adopted:

> Given that a resolution of the difficult issues in the conference were necessary to conclude work on this bill, the Senate proposed to recede to the House provision which was taken from the original administration bill. It provides for a 3-year study of utility emissions followed by regulation to the extent that the Administrator finds them necessary.

Id.

Senator Durenberger's statements indicate that it is unlikely that he would agree with Oxley's interpretation of CAA section 112(n)(1), a provision that provides the Agency with considerable discretion, and nothing indicates that others in the Senate (or for that matter anyone else in the House) would agree with that interpretation. Given the Supreme Court's views on the use of such limited legislative history, the EPA reasonably declined to consider (or even discuss) the legislative history in the preamble to the proposed rule and we believe it would be improper to ascribe Representative Oxley's statements to the entire Congress.

Moreover, Representative Oxley's statement directly conflicts with the statutory text. Representative Oxley stated that ''[the Administrator 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.'' 136 Cong. Rec. H12934 (daily ed. Oct. 26, 1990), reprinted in 1 1990 Legis. Hist. at 1416–17 *(emphasis added)*. However, the Utility Study required under CAA section 112(n)(1)(A) directs the Agency to consider the hazards to public health reasonably anticipated to occur after ''imposition of the requirements of [the Clean Air Act].'' EPA was not required to consider state or local regulations or voluntary emission reduction programs in the Utility Study, and that study is the only condition precedent to making the appropriate and necessary finding.[55]

The legislative history the commenters rely on is not controlling. The Agency believes that it has reasonably interpreted section 112(n)(1)(A), for all the reasons described herein and in the proposal. The commenters also cite Representative Oxley's statements as support for alternative interpretations of CAA section 112(n)(1). We believe that any arguments that rely on such limited legislative history are without merit.

Comment: One commenter stated that the EPA does acknowledge that, in many significant respects, its new interpretation of CAA section 112(n)(1) ''differs from that set forth'' in the Agency's 2005 rulemaking, but argues that its change of position is permissible. *See* 76 FR 24988/1 (''[T]o the extent our interpretation differs from that set forth in the 2005 Action, we explain the basis for that difference and why the interpretation, as set forth in this preamble, is reasonable.''). In support, commenters note that the EPA cites *National Cable & Telecommunication Ass'n* v. *Brand X Internet Services,* 545 U.S. 967 (2005). The commenters agree that it is true that, in *Brand X Internet Services,* the Supreme Court explained that, if an agency ''adequately explains the reasons for a reversal of policy,'' such change is ''not invalidating,'' since the ''whole point of Chevron is to leave the discretion provided by the ambiguities of a statute with the implementing agency.'' 545 U.S. at 981 (internal quotations omitted). The commenters maintain that all Brand X Internet Services was saying is that ''[a]gency inconsistency is not a basis for declining to analyze the agency's interpretation under the *Chevron* framework.'' *Id.*

According to the commenter, it is not enough that the EPA has purported to ''explain'' why it has abandoned the interpretation of CAA section 112(n)(1) adopted in 2005. The commenter states that under the first step of *Chevron*, the Agency's latest interpretation must still be consistent with congressional intent. *See Chevron* v. *NRDC,* 467 U.S. at 842–43. The commenters state that under the second step of Chevron, if there is discretion for EPA to exercise in interpreting the ''critical terms'' of CAA section 112(n)(1), the Agency must properly define the range of that discretion and then act reasonably in exercising that discretion. *See Chevron,* 467 U.S. at 843; *see also Village of Barrington, Ill.* v. *Surface Transportation Bd.,* No. 09–1002 (D.C. Cir. Mar. 15, 2011).The commenters allege that the EPA failed to properly define and exercise the scope of its discretion. In each instance, the commenter maintains that the Agency has departed from the correct interpretation of CAA section 112(n)(1) that it adopted in 2005, seizing instead upon a new approach that is contrary to the plain language of the CAA itself, as interpreted after considering the statements of Representative Oxley.

Response: The commenter appears to argue that the EPA's interpretation of CAA section 112(n)(1) is not consistent with the plain language of the statute, implying that the statute is clear and must be evaluated under step one of Chevron. *See Chevron* v. *NRDC,* 467 U.S. 837 842–42 (1984) (finding that when the legislative intent is clear no additional analysis is required).

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[55] In addition, the EPA only considered CAA requirements in the Utility Study and this was the correct approach because Congress knew how to require consideration of non-Federal requirements when directing EPA to conduct a study or assessment. See CAA section 112(n)(5) (Congress required EPA to conduct an assessment of hydrogen sulfide from oil and gas extraction activities and provided that the assessment ''shall include review of existing State and industry control standards, techniques and enforcement.'').

However, as noted above, much of the commenter's argument that the plain language of the statute precludes EPA's interpretation is based on the unpersuasive legislative history discussed above. As explained in the preamble to the proposed rule, the statute directs the Agency to determine whether it is appropriate and necessary to regulate EGUs under section 112. As the D.C. Circuit has held, the terms ''appropriate'' and ''necessary'' are very broad terms. Because these terms are broad they are susceptible to different interpretations. We believe we have reasonably interpreted the appropriate and necessary language in section 112(n)(1)(A). To the extent that interpretation differs from the one set forth in 2005, we have fully explained the basis for such changes. *See* 76 FR 24986–24993 (setting forth the Agency's interpretation of section 112(n)(1)).

Furthermore, we properly considered the scope of our discretion in interpreting the statute as explained in detail in the preamble to the proposed rule. We believe the interpretation set forth in the preamble to the proposed rule is consistent with the Act and, therefore, the Agency should be afforded deference pursuant to *National Cable & Telecommunication Ass'n* v. *Brand X Internet Services,* 545 U.S. 967 (2005).

Comment: A number of commenters agreed with the Agency's interpretation of section 112(n)(1) and the terms appropriate and necessary. The commenters also agreed that the EPA's interpretation of that provision was reasonable and consistent with the statute.

Response: We agree with the commenters and appreciate their support.

Comment: One commenter asserts that the EPA's ultimate motivation for rejecting its prior interpretation of CAA section 112(n)(1) and embracing this flawed new approach is made clear from the very outset of the proposal. According to the commenter, the EPA touts the fact that ''one consequence'' of the MACT rule would be that the ''market for electricity in the U.S. will be more level'' and ''no longer skewed in favor of the higher polluting units that were exempted from the CAA at its inception on Congress' assumption that their useful life was near an end.'' *See* 76 FR 24979/2. The MACT rule would ''require companies to make a decision—control HAP emissions from virtually uncontrolled sources'' or else ''retire these sometimes 60 year old units and shift their emphasis to more efficient, cleaner modern methods of generation, including modern coal-fired generation.'' Id.

The commenter stated that this remarkably forthright statement establishes that the underlying basis for EPA's proposal to regulate EGUs under CAA section 112 is not to address any ''hazards to public health'' that might be attributed to the emission by EGUs of HAP listed under CAA section 112(b). Rather, according to commenter, the EPA is utilizing the regulation of EGUs under CAA section 112 as a means to an entirely different end: To force the imposition of controls that will also have the result of reducing non-HAP emissions (primarily PM) or force the shutdown of those units for which the cost of such controls would be prohibitive. At the same time, according to commenter, the EPA tacitly acknowledges that it cannot hope to make out a case that the regulation of EGU HAP emissions is ''appropriate and necessary'' within the meaning of CAA section 112(n)(1). The commenter asserts that the only HAP whose health-related benefits EPA quantifies is Hg. Elsewhere, the commenter stated that the EPA contends there are ''additional health and environmental effects'' attributable to HAP other than Hg, but admits that it has ''not quantified'' those risks due supposedly to ''insufficient information.'' *See* 76 FR 24999/2. With respect to Hg the commenter stated that the benefits are so questionable and miniscule, some $4 million to $6 million (given a 3 percent discount rate), that compared to the total social costs of the rule (*i.e.,* nearly $11 billion) the rule cannot be justified were EPA properly to interpret CAA section 112(n)(1) and undertake the sort of regulatory analysis Congress intended. The commenter stated that the reason that the EPA touts in this rulemaking the health benefits EPA attributes to the reduction of non-hazardous air pollutants (again, primarily PM), the regulation of which is authorized under provisions of the CAA apart from CAA section 112, is to elide the inconvenient truth regarding the truly trivial nature of the benefits attributable to HAP regulation itself. The commenter concludes that the EPA distorts CAA section 112(n)(1)(A) ''beyond all recognition.''

One commenter stated that the EPA is directed by CAA section 112(n)(1)(A) to study the ''hazards to public health anticipated to occur as a result of emissions'' by EGUs of ''pollutants listed under subsection (b) of this section''—*i.e.,* HAP and HAP alone. Thereafter, the EPA is authorized to regulate EGU HAP emissions if, and only if, they determine that ''such regulation'' of HAP emissions is ''appropriate and necessary'' to address the ''hazards to public health'' that may be attributable to HAP emissions. According to the commenter, by contrast, in this rulemaking, the EPA has seized upon the fact that the control of EGU HAP emissions will also control non-HAP (such as PM), and then seeks to justify the regulation of HAP emissions based almost entirely on the health benefits of the reductions in non-HAP emissions that would be coincidentally achieved. The commenter believes that this ''regulatory sleight-of-hand'' runs afoul of congressional intent and is unlawful.

Response: The commenter alleges that the health-related benefits to regulating HAP emissions from EGUs are ''questionable and miniscule,'' and that the only real benefits stem from non-HAP emissions, such as PM. The commenter also implies that regulation of HAP is nothing more than a straw man and that the Agency's ultimate goal is to regulate other pollutants, and specifically PM. These allegations are wholly without merit. The Agency has conducted comprehensive technical analyses that confirm that HAP emissions from EGUs pose a hazard to public health. The analyses are discussed at length elsewhere in this final rule, and a review of the proposed and final rules utterly refutes commenter's assertion that PM reductions form the basis for the appropriate and necessary finding. In addition, the commenter appears to ignore the Agency's findings concerning the hazards to public health and the environment posed by HAP emissions simply because the Agency is not able to quantify many of the benefits associated with reductions of HAP emissions from EGUs or because the estimated HAP benefits that are quantified are small in relation to the co-benefits achieved through reductions in non-HAP air pollutants, such as PM and SO_2, which are surrogates for certain HAP. The Agency is regulating EGUs pursuant to section 112(d) for all of the reasons explained in the preamble and discussed elsewhere in this response to comments. The commenter fails to recognize that the statute neither requires a cost-benefit analysis prior to finding it appropriate and necessary to regulate EGUs, nor requires such analysis prior to setting emission standards. Indeed, Congress expressly precluded consideration of costs when setting MACT floors. As explained below, the EPA does not believe that it is appropriate to consider costs when determining whether to regulate EGUs under CAA section 112.

Comment: One commenter stated that the EPA has ignored the language and intent of CAA section 112(n)(1)(A), as interpreted based on Representative Oxley's statements, and that the Agency's interpretation of this provision violates step one of Chevron. Under Chevron where the ''intent of Congress is clear,'' that is the ''end of the matter,'' for both the implementing agency and a reviewing court ''must give effect to the unambiguously expressed intent of Congress.'' Chevron, 467 U.S. at 842–43. The commenter asserts that the legislative history of CAA section 112(n)(1)(A) ''sheds considerable light on Congress' unique approach to regulation of EGUs under CAA § 112.'' According to the commenter, on April 3, 1990, the Senate passed S. 1630. The Senate bill would have required EPA to list EGUs under CAA section 112(c) and to regulate them under the MACT provisions of CAA section 112(d). *See* S. 1630 section 301, 3 1990 Legis. Hist. at 4407. Thereafter, the House of Representatives passed a modified version of S. 1630 on May 23, 1990. This House version substantially changed the provisions of CAA section 112 as they applied to EGUs. *See* 1 1990 Legis. Hist. at 572–73. The House version was virtually identical to the current CAA section 112(n)(1)(A), and was ultimately adopted by the conference committee, enacted by Congress and signed into law. According to the commenter, Congress expressly rejected the ''list-under-(c)-and-regulate-under-(d)'' approach that S. 1630 would have applied to EGUs, and that Congress did choose to apply to other source categories. The commenter stated that the EPA's interpretation that the Agency is ''required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)'' (Id. at 24,993/3) fails to take the legislative history into account, and in a footnote, the commenter states that the Agency erred by not addressing the legislative history as it did in the 2005 action.

Response: For the reasons stated above, we believe commenter's reliance on the single statement of one legislator is flawed. In addition, in a footnote the commenter stated that the EPA recognized ''that it had to address'' the legislative history in its 2005 action, and that the EPA erred in this case because we did not address the legislative history. The commenter cites no case law to support its contention that an Agency must ''address'' unpersuasive legislative history. Further, in the 2005 action, the EPA relegated to a footnote the Oxley statement that commenter relies on so heavily even though the statement supported the interpretation we provided in that rule. We recognized then what the commenter fails to recognize now, which is that the Agency cannot argue that the meaning of CAA section 112(n)(1)(A) is clear based on the statements of one legislator.

Furthermore, the Agency's interpretation does not violate Chevron Step 1. The terms ''appropriate'' and ''necessary'' are ambiguous. The statements of a lone legislator do not transform those ambiguous words into a Chevron Step 1 situation.

Moreover, the commenter's assertion that Congress unambiguously defined the factors to consider in making the appropriate determination is without merit. We fully explain in the preamble to the proposed rule the basis for the Agency's interpretation, and we are not revising that interpretation based on the comments received.

Finally, the EPA notes that the sentence concerning regulation under CAA section 112(d) that the commenter quotes from the preamble states, in full: ''Congress did not exempt EGUs from the other requirements of section 112 and, *once listed*, the EPA is required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d), as described above.'' 76 FR 24993 (*emphasis added*). The EPA discusses requirements to regulate section 112(c) listed sources under section 112(d) in response to other comments.

c. Consideration of Both Environmental Effects and Health Effects From Other Sources

Comment: Several commenters stated that the EPA acts contrary to congressional intent when the Agency considers itself ''thereby authorized to consider 'environmental effects' and the effects of HAP emissions from non-EGU sources, in making its 'appropriate and necessary' finding under subparagraph (n)(1)(A).''

Commenters assert that the EPA misreads CAA section 112(n)(1)(B) and (C) to inject environmental effects in the CAA section 112(n)(1)(A) determination. According to one commenter the plain language of CAA section 112(n)(1) establishes that regulation of EGUs is to be predicated solely on ''hazards to public health'' attributable to HAP emissions. The legislative history providing that the EPA ''may regulate [EGUs] only if the studies described in section 112(n) clearly establish that emissions of any pollutant * * * from such units cause a significant risk of serious adverse risk to the public health'' confirms that plain language. *See* Oxley Statement at 1416–17. The commenter further stated that nothing on the face of CAA section 112(n)(1)(A) indicates that Congress intended that the EPA should (or must) take into account any additional information that might be developed through the other studies mentioned in subparagraphs (n)(1)(B) and (C) (*i.e.*, the Mercury Study [56] and the NAS Study [57]), such as HAP emissions from non-EGU sources. The commenter also identified other provisions of section 112 that specifically require consideration of environmental effects and states that Congress would have requires such consideration in CAA section 112(n)(1) if it had wanted EPA to consider environmental effects.

The commenter makes a related assertion that the EPA acts contrary to congressional intent by assuming authority to assess the '''hazard to public health or the environment [from] HAP emissions from EGUs alone' or the 'result of HAP emissions from EGUs in conjunction with HAP emissions from other sources''' (citing 76 FR at 24,988/1). According to the commenter, the only evident basis for the Agency's interpretation that, in making its ''appropriate and necessary'' finding, the EPA can (and should) take into account HAP emissions from sources other than EGUs, is that the Mercury Study authorized by CAA 112(n)(1)(B) references ''mercury emissions from * * * municipal waste combustion units, and other sources, including area sources,'' in addition to EGUs. The commenter asserts, however, that subparagraph (n)(1)(A) identifies the Utility Study as the sole study to inform EPA's ''appropriate and necessary'' finding. The commenter states that if Congress had intended that the EPA take into account information developed through the Mercury Study, Congress ''would not have specified that the EPA was to predicate its 'appropriate and necessary' finding on the 'results of the study required by this subparagraph' (n)(1)(A).''

Commenter also cites to a number of other section 112 provisions that expressly address environmental effects and the commenter states the only conclusion to draw from the inclusion in those provisions and the absence of such language in section 112(n)(1)(A) is that Congress intended public health to be the only basis for the appropriate and necessary finding.

[56] U.S. EPA. 1997. *Mercury Study Report to Congress.* EPA–452/R–97–003. December.

[57] NAS, 2000.

Response: The commenter again relies in part on the statements of one legislator to attack EPA's reasoned interpretation of an ambiguous statute. To the extent the commenter's arguments rely on this limited evidence, we refer to the response above. As we stated above, CAA section 112(n)(1) is an ambiguous statutory provision; thus, the EPA's interpretation, not commenter's, is entitled to considerable deference if it is a reasonable reading of the statute. *Chevron*, 467 U.S. at 843–44. For the reasons described herein and in the proposal, we believe that we have reasonably interpreted the statutory terms at issue here. The Agency directs attention to section III.A. of the proposed rule, which includes a thorough discussion of the Agency's interpretation of the relevant statutory terms. To the extent the commenters disagree with EPA's interpretations, the EPA refers back to its discussion in the proposal and responds to the comments as follows.

The commenter appears to maintain that the EPA must interpret the scope of the appropriate and necessary finding solely in the context of the CAA section 112(n)(1)(A) Utility Study, such that only hazards to public health and only EGU HAP emissions may be considered. The commenter incorrectly conflates the requirements for the Utility Study with the requirement to regulate EGUs under CAA section 112 if EPA determines it is appropriate and necessary to do so. The commenter concedes that the Agency may consider information other than that contained in the Utility Study, but only to the extent it relates specifically to hazards to public health directly attributable to HAP emissions from EGUs. We agree that we may consider additional information other than that contained in the Utility Study, as we stated in the preamble to the proposed rule, because courts do not interpret phrases like ''after considering the results of'' in a manner that precludes the consideration of other information. *See United States* v. *United Technologies Corp.*, 985 F.2d 1148, 1158 (2nd Cir. 1993) (''based upon'' does not mean ''solely); [58] *see also* 76 FR 24988. We further explained in the preamble to the proposed rule that it was reasonable to interpret the scope of the appropriate and necessary finding in the context of all three studies required under CAA section 112(n)(1) because the provision is title ''Electric utility steam generating units.'' [59] The commenter has provided little more than unpersuasive legislative history to support its restrictive interpretation of our authority. *Id.*

The commenter also argues that the statute clearly prohibits the Agency from considering adverse environmental effects or the cumulative effects of HAP emissions from EGUs and other sources based on its claim that the statute is clear when one *properly* considers the legislative history. Again, the commenter has provided no support for its contention other than the statements of one Representative and the improper conflation of the CAA section 112(n)(1)(A) direction on the conduct of the Utility Study and the appropriate and necessary finding. Congress left it to the Agency to determine whether it is appropriate and necessary to regulate EGUs under CAA section 112 and the statute does not limit the Agency to considering only hazards to public health and only harms directly and solely attributable to EGUs.

The commenter stated that Congress specifically told EPA when it wanted EPA to consider adverse environmental effects in CAA section 112 and cites to several provisions of the Act that require consideration of adverse environmental effects. The commenter ignores CAA section 112(n)(1)(B), which directs the Agency to consider adverse environmental effect. In any event, even were we to view section 112(n)(1)(A) in isolation, as the commenter suggests, we still maintain that we can consider adverse environmental effects under 112(n)(1)(A). Nothing in section 112(n)(1)(A) precludes consideration of environmental effects. Congress required the Agency to assess whether it is appropriate and necessary to regulate EGUs under section 112. We believe that adverse environmental effects can be considered in the appropriate analysis. Congress specifically directed the Agency to consider adverse environmental effects when delisting source categories pursuant to section 112(c)(9), and thus we believe it is reasonable to consider such effects when determining whether it is appropriate to regulate such units under section 112, especially given that Congress did not limit our appropriate and necessary inquiry to the Utility Study. See CAA section 112(c)(9)(B)(ii).

Moreover, the other provisions of CAA section 112 that specifically discuss environmental effects have purposes that are distinguishable from CAA section 112(n)(1), and we do not believe one can reasonably draw the conclusion that the commenter does when comparing those provisions to CAA section 112(n)(1)(A). The lack of a requirement to consider environmental effects in CAA section 112(n)(1)(A) does not equate to a prohibition on the consideration of environmental effects as the commenter concludes. The EPA maintains that it reasonably concluded that we should protect against identified or potential adverse environmental effects absent clear direction to the contrary.

Concerning the consideration of the cumulative effect of HAP emissions from EGUs and other sources, we provided a reasonable interpretation of the statute and noted that our interpretation, unlike commenters, does not ''ignore the manner in which public health and the environment are affected by air pollution. An individual that suffers adverse health effects as the result of the combined HAP emissions from EGUs and other sources is harmed, irrespective of whether HAP emissions from EGUs alone would cause the harm.'' [60]

d. Finding for All HAP To Be Regulated

Comment: Several commenters stated that for those EGU HAP for which the Agency makes no CAA section 112(n)(1)(A) determination, their regulation under CAA section 112 is not authorized. For example, one commenter maintains that the Agency could regulate HAP emissions from EGUs under CAA section 112(n). Accordingly, to the extent that the EPA reads CAA section 112, as construed by *National Lime Ass'n,* as compelling it to regulate all HAP emitted by EGUs, should the Agency make an ''appropriate and necessary'' determination under CAA section 112(n)(1)(A) with respect to a single HAP (*e.g.*, Hg), the EPA stands poised to commit a fundamental legal error that will condemn the final rule on review. Cf., *e.g.*, *PDK Laboratories, Inc.*, 362 F.3d at 797–98; *Holland* v. *Nat'l Mining Ass'n*, 309 F.3d at 817 (where an agency applies a Court of Appeals ''interpretation * * * because it believed that it had no choice'' and that it ''was effectively 'coerced' to do so,'' then the agency ''cannot be deemed to have exercised its reasoned judgment'').

Response: We do not agree with the commenter's assertion that Congress intended EPA to regulate only those EGU HAP emissions for which an appropriate and necessary finding is

[58] Several commenters have taken issue with our citation to *United States* v. *United Technologies Corp.* because the language at issue in that case was ''based upon'' and the language of section 112(n)(1)(A) is ''after considering the results of.'' We believe that, if anything, ''based upon'' is more prescriptive than ''after considering the results of'' such that the case supports the Agency's interpretation that additional information other than the Utility Study may be considered in making the appropriate and necessary finding.

[59] 76 FR 24986–87.

[60] 76 FR 24988.

made, and the commenter has cited no provision of the statute that states a contrary position. The EPA reasonably concluded that we must find it ''appropriate'' to regulate EGUs under CAA section 112 if we determine that a single HAP emitted from EGUs poses a hazard to public health or the environment. If we also find that regulation is necessary, the Agency is authorized to list EGUs pursuant to CAA section 112(c) because listing is the logical first step in regulating source categories that satisfy the statutory criteria for listing under the statutory framework of CAA section 112. *See New Jersey,* 517 F.3d at 582 (stating that ''[s]ection 112(n)(1) governs how the Administrator decides whether to list EGUs. * * *''). As we noted in the preamble to the proposed rule, D.C. Circuit precedent requires the Agency to regulate all HAP from major sources of HAP emissions once a source category is added to the list of categories under CAA section 112(c). *National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633 (D.C. Cir. 2000). 76 FR 24989.

The commenter does not explain its issues with our interpretation of how regulation under section 112 works—*i.e.* making a determination that a source category should be listed under CAA section 112(c), listing the source category under CAA section 112(c), regulating the source category under CAA section 112(d), and conducting the residual risk review for sources subject to MACT standards pursuant to CAA section 112(f). Instead, it asserts that our decision is flawed because the interpretation we provided does not account for all the alternatives for regulating EGUs under section 112, and that we have not properly exercised our discretion leading to a fatal flaw in our rulemaking.

The commenter also ignores the language of section 112(n)(1)(A). As explained in the proposed rule, the use of the terms section, subsection, and subparagraph in section 112(n)(1)(A) demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing EPA's action under section 112(n)(1)(A). Congress directed the Agency to regulate utilities ''under this section,'' not ''under this subparagraph,'' and accordingly EGUs should be regulated under section 112 in the same manner as other categories for which the statute requires regulation. Furthermore, the D.C. Circuit Court found that section 112(n)(1) ''governs how the Administrator decides whether to list EGUs'' and that once listed, EGUs are subject to the requirements of section 112. *New Jersey,* 517 F.3d at 583. Indeed, the D.C. Circuit Court expressly noted that ''where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly,'' noting that ''section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants.'' *Id.* Congress did not exempt EGUs from the other requirements of section 112, and once listed, the EPA is reasonably regulating EGUs pursuant to the standard-setting provisions in section 112(d), as it does for all other listed source categories.

The commenter provided no alternative theory for regulating EGUs under CAA section 112, other than to state that the EPA could regulate under CAA section 112(n)(1). However, even assuming for the sake of argument, that we could issue standards pursuant to CAA section 112(n)(1), we would decline to do because there is nothing in section 112(n)(1)(A) that provides any guidance as to how such standards should be developed. Any mechanism we devised, absent explicit statutory support, would likely receive less deference than a CAA section 112(d) standard issued in the same manner in which the Agency issues standards for other listed source categories. We would also decline to establish standards under section 112(n)(1) because Congress did provide a mechanism under CAA sections 112(d) and (f) for establishing emission standards for HAP emissions from stationary sources and it is reasonable to use that mechanism to regulate HAP emissions from EGUs.

e. Considering Costs in Finding

Comment: Several commenters assert that the EPA must consider costs in assessing whether regulation of EGUs is appropriate under CAA section 112(n)(1)(A). Commenters posit that the EPA's position that ''the term 'appropriate' * * * does not allow for the consideration of costs in assessing whether hazards * * * are reasonably anticipated to occur based on EGU emissions,'' 76 FR at 24,989/1, does not withstand scrutiny. According to the commenters, the treatment of ''costs'' under section 112(c) does not support the Agency's position, and the process by which sources may be ''delisted'' under section 112(c)(9), including no consideration of costs, sheds no light on the circumstances under which it may be ''appropriate'' to regulate EGUs under section 112(n)(1)(A).

Commenters characterize as ''unintelligible'' the EPA's position that it is ''reasonable to conclude that costs may not be considered in determining whether to regulate EGUs'' when ''hazards to public health and the environmental are at issue (citing 76 FR at 24989). ''Two commenters stated that a natural reading of the term ''appropriate'' would include the consideration of costs. According to the commenters, something may be found to be ''appropriate'' where it is ''specially suitable,'' ''fit,'' or ''proper.'' *See* Webster's Third New International Dictionary at 106 (1993). The term ''appropriate'' carries with it the connotation of something that is ''suitable or proper in the circumstances.'' *See* New Oxford American Dictionary (2d Ed. 2005). Considering the costs associated with undertaking a particular action is inextricably linked with any determination as to whether that action is ''specially suitable'' or ''proper in the circumstances.'' One commenter notes that in 2005 (70 FR 15994, 16000; March 29, 2005) the EPA used the dictionary definition of ''appropriate,'' as being ''especially suitable or compatible'' and that it would be difficult to fathom how a regulatory program could be either ''suitable'' or ''compatible'' for a given public health objective without consideration of cost.

One commenter asserts that on the face of CAA section 112(n)(1)(A), it is clear that the EPA is expected to consider costs. According to the commenter, that Congress intended that the EPA investigate and consider ''alternative control strategies'' for emissions as part of the section 112 (n)(1) Utility Study when making the ''appropriate and necessary'' determination refutes the notion that the Agency can, and indeed must, disregard the cost of regulation in making that determination, because the cost of a given emission ''control strategy'' is a central factor in any evaluation of ''alternative'' controls.

Further, according to commenters, it is well-settled that CAA regulatory provisions should be read with a presumption in favor of considering costs (citing *Michigan* v. *EPA,* 213 F.3d 663, 678 (D.C. Cir. 2000)), and the legislative history of section 112(n)(1)(A) confirms that Congress intended EPA to consider costs (citing Oxley Statement at 1417).

Commenters also assert that the EPA falsely represents that it ''did not consider costs when making the ''appropriate'' determination in the EPA's December 2000 notice (76 FR at 24,989/2).

Response: The commenters first take issue with EPA's explanation of why the Agency determined that costs should not be considered in making the appropriate determination. What commenters do not identify is an express statutory requirement that the Agency consider costs in making the appropriate determination. Congress treated the regulation of HAP emissions differently in the 1990 CAA amendments because the Agency was not acting quickly enough to address these air pollutants with the potential to adversely affect human health and the environment. *See New Jersey,* 517 F.3d at 578. Specifically, following the 1990 CAA amendments, the CAA required the Agency to list source categories and nothing in the statute required us to consider costs in those listing decision, and we have not done so when listing other source categories. Thus, it is reasonable to make the listing decision, including the appropriate determination, without considering costs.

The commenters next argue that the Agency is compelled by the statute to consider costs based on a dictionary definition of ''appropriate'' and the CAA section 112(n)(1)(A) direction to consider alternative control strategies for regulating HAP emissions in the Utility Study.

Concerning the definition of ''appropriate'', commenters stated:

> Not only is it ''reasonable'' for EPA to consider costs in determining whether it is ''appropriate'' to regulate EGU HAP emissions, a natural reading of the term indicates that excluding the consideration of costs would be entirely unreasonable. Something may be found to be ''appropriate'' where it is ''specially suitable,'' ''fit,'' or ''proper.'' *See* Webster's Third New International Dictionary at 106 (1993). The term ''appropriate'' carries with it the connotation of something that is ''suitable or proper in the circumstances.'' *See* New Oxford American Dictionary (2d Ed. 2005) at 76. Considering the costs associated with undertaking a particular action is inextricably linked with any determination as to whether that action is ''specially suitable'' or ''proper in the circumstances.''

The EPA believes the definition of ''appropriate'' that the commenters provide wholly support its interpretation and nothing about the definition compels a consideration of costs. It is appropriate to regulate EGUs under CAA section 112 because EPA has determined that HAP emissions from EGUs pose hazards to public health and the environment, and section 112 is ''specially suitable'' for regulating HAP emissions, and Congress specifically designated CAA section 112 as the ''proper'' authority for regulating HAP emissions from stationary sources, including EGUs. Section 112 of the CAA is ''suitable [and] proper in the circumstances'' because EPA has identified a hazard to public health and the environment from HAP emissions from EGUs and Congress directed the Agency to regulate HAP emissions from EGUs under that provision if we make such a finding. Cost does not have to be read into the definition of ''appropriate'' as commenter suggests. In addition, as stated elsewhere in response to comments, the Agency does not consider costs in any listing or delisting determinations, and the EPA maintains that it is reasonable to assess whether to list EGUs (*i.e.* the appropriate and necessary finding) without considering costs.

The commenters' argument that costs must be considered based on the CAA section 112(n)(1)(A) requirement to ''develop and describe alternative control strategies'' in the Utility Study is equally flawed. The argument is flawed because Congress did not direct the Agency to consider in the Utility Study the costs of the controls when evaluating the alternative control strategies. In addition, the EPA did not consider the costs of the alternative controls in the Utility Study, as implied by the commenter. Thus, even viewing section 112(n)(1)(A) in isolation, there is nothing in that section that compels EPA to consider costs. For the reasons described herein, we do not believe that it is appropriate to consider costs in determining whether to regulate EGUs under section 112.

Additionally, one commenter attempts to refute EPA's statement in the preamble to the proposed rule that the EPA did not consider costs in the 2000 finding by pointing to the only two mentions of cost in that notice. However, the EPA did not say that costs were not mentioned in the 2000 finding and a review of the regulatory finding will show that costs were not considered in the regulatory finding. 65 FR 79830 (December 20, 2000) (''Section III. What is EPA's Regulatory Finding?'').

f. Considering Requirements of the CAA in ''Necessary''

Comment: Several commenters disagree with EPA's position that it need consider ''only those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990,'' for which ''EPA could reasonably predict HAP emission reductions at the time of the Utility Study.'' According to the commenters, the statutory language of CAA section 112(n)(1) requires that the EPA consider the scope and effect of EGU HAP emissions after the imposition of all of the ''requirements'' of the CAA, not just the Acid Rain program. The commenter maintains that it would have been easy enough for Congress in subparagraph 112(n)(1)(A) to specify ''after imposition of the requirements of Title IV of this chapter,'' but Congress did not. The commenters further add that the legislative history confirms that Congress meant something much broader than that, providing that the EPA is authorized to regulate EGUs under CAA section 112 only after ''taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions.'' The commenters stated that the CAA's ''requirements'' include the submission by states of ozone and fine PM attainment demonstrations, as well as SIP provisions needed to reach attainment of the NAAQS because such provisions could include controls on EGUs to reduce SO_2 and NO_X, which controls could also result in a reduction in Hg emissions.

Response: The commenter's characterization of the facts is flawed and its reliance on legislative history that is in direct conflict with the express terms of the statute is unpersuasive.

On the facts, the EPA explained in the preamble to the proposed rule its interpretation of the phrase ''after imposition of the requirements of [the Act]'' as it related to the conduct of the Utility Study.[61] We reasonably concluded that, since Congress only provided 3 years after enactment to conduct the study, the phrase referred to requirements that were directly imposed on EGUs through the CAA amendments and for which the Agency could reasonably predict co-benefit HAP emission reductions. *Id.* The EPA did not state that the phrase only applied to the Acid Rain program, as commenter asserts, and the Utility Study in fact discussed other regulations, including the NSPS for EGUs and revised NAAQS. With regard to the latter, the EPA ultimately determined that it could not sufficiently quantify the reductions that might be attributable to the NAAQS because states are tasked with implementing those standards. *See* Utility Study, pages ES–25, 1–3, 2–32. Conversely, commenter's position is that the EPA must consider implementation of *all* the requirements of the CAA, but it does not indicate how in conducting the Utility Study the Agency could have possibly considered co-benefit HAP reductions attributable to all future CAA requirements. The Agency appropriately considered the other requirements of the Act in the Utility Study and considered those requirements in determining that it was

[61] 76 FR 24990.

necessary to regulate coal- and oil-fired EGUs in December 2000.

Although not required, the Agency in the preamble to the proposed rule conducted further analyses in support of the 2000 finding. In doing so, we considered a number of requirements that far exceed what Congress contemplated when enacting CAA section 112(n)(1)(A)), and our analyses still show that it remains necessary to regulate coal- and oil-fired EGUs under section 112. 76 FR 24991.

We maintain that we have reasonably interpreted the requirement to consider the hazards to public health and the environment reasonably anticipated to occur after imposition of the requirements of the Act as explained in the preamble to the proposed rule.[62] In addition, as stated above, we also believe it would be reasonable to find it necessary to regulate HAP emissions from EGUs based on our finding that such emissions pose a hazard to public health and the environment today without considering future reductions that we currently project to occur as the result of imposition of CAA requirements that are not yet effective (*e.g.,* CSAPR).

Moreover, Representative Oxley's statement cited by the commenter is not consistent with the express terms of CAA section 112(n)(1)(A) on this issue. Representative Oxley stated that the EPA was to take ''into account compliance with all the provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions,'' but CAA section 112(n)(1)(A) directs the Agency to consider ''imposition of the requirements of this chapter,'' which means the CAA. The Agency reasonably focused on the requirements of the Clean Air Act, which are federally enforceable, and declined to include potential future reductions that may be attributable to voluntary emission reduction programs or state and local regulations that have no basis in the Clean Air Act and are not federally enforceable. In addition to the statutory direction not to consider such requirements, the EPA believes it is reasonable not to include potential reductions attributable to such requirements because the Agency cannot assure that such requirements and the attendant HAP reductions will remain absent regulation under section 112. Finally, the commenter implies that EPA's position is that the Agency will only consider requirements of the Act that directly regulate HAP emissions. The EPA never stated or suggested that interpretation and a fair reading of the proposed rule will demonstrate that EPA considered requirements that achieve co-benefit HAP emission reductions, for example the Transport Rule (known as CSAPR).

Comment: One commenter stated that, under CAA section 112, regulating EGUs is permissible only insofar as it is focused, targeted, and predicated on concrete findings by the Agency that such regulation is indeed ''necessary.'' According to the commenter, the EPA construes CAA section 112(n)(1)(A) as permitting it to find that it is ''necessary'' to regulate EGUs even where the Agency does not actually know whether it is ''necessary'' to regulate EGUs. Citing the D.C. Circuit, the EPA suggests that '''there are many situations in which the use of the word 'necessary,' in context, means something that is done, regardless of whether it is indispensible,''' in order to '''achieve a particular end.''' 76 FR 24990, quoting *Cellular Telecommunications* v. *FCC,* 330 F.3d 502, 510 (D.C. Cir. 2003). The commenter stated that in the ''context'' of CAA section 112(n)(1)(A), as informed by the relevant legislative history from Representative Oxley, it is clear that regulation of EGU HAP emissions can be considered ''necessary'' only if EPA were to ''clearly establish'' that such regulation was effectively ''indispensible'' to address the identified harm. As EPA concedes that it has made no such determination here, its proposal is fatally flawed for that reason alone.

The commenter further asserts that the EPA erred when it concluded that it may '' 'determine it is necessary to regulate under section 112' when the Agency is 'uncertain whether imposition of the requirements of the CAA will address the identified hazards''' (citing 76 FR at 24,991/3). According to the commenter, the EPA ''cannot take refuge in its own 'uncertainty' to support a finding that it is 'necessary' to regulate EGUs under section 112, and the Act precludes the EPA from '''err[ing] on the side of regulation''' in face of uncertainty (*id.*). The commenter also implies that the finding was based on non-HAP emissions.

Response: The commenter again relies on the legislative statements of one Representative and asserts that the statements are controlling. The EPA disagrees with commenter and maintains that its interpretation of the term ''necessary'' is reasonable. 76 FR 24990–92 (Section III.A.2.b of the preamble to the proposed rule contains the EPA's interpretation of the term ''necessary''.) 76 FR 24990–92 (Section III.A.2.b of the proposed rule contains EPA's interpretation of the term ''necessary''.) The commenter also, in a footnote, implies that EPA based the appropriate and necessary finding on non-HAP air pollution. The commenter is wrong as explained in more detail above.

As an initial matter, this comment is only addressing one aspect of the Agency's interpretation of the term necessary. As EPA stated at proposal:

> If we determine that the imposition of the requirements of the CAA will not address the identified hazards, EPA must find it necessary to regulate EGUs under section 112. Section 112 is the authority Congress provided to address hazards to public health and the environment posed by HAP emissions and section 112(n)(1)(A) requires the Agency to regulate under section 112 if we find regulation is ''appropriate and necessary.'' If we conclude that HAP emissions from EGUs pose a hazard today, such that it is appropriate, and we further conclude based on our scientific and technical expertise that the identified hazards will not be resolved through imposition of the requirements of the CAA, we believe there is no justification in the statute to conclude that it is not necessary to regulate EGUs under section 112.

76 FR 24991.

The EPA has determined that the imposition of the requirements of the CAA will not address the hazards to public health or hazards to the environment that EPA has identified; therefore, it is necessary to regulate EGUs under CAA section 112.

The EPA further interpreted the statute to allow the Agency to find that it is necessary to regulate EGUs under other circumstances, and it is with one of our additional interpretations that commenter takes issue. Specifically, the commenter argues that EPA's interpretation authorizes the Agency to find it necessary to regulate EGUs when we are uncertain it is necessary, but that misconstrues our interpretation and the record. At proposal, the EPA stated:

> In addition, we may determine it is necessary to regulate under section 112 even if we are uncertain whether the imposition of the requirements of the CAA will address the identified hazards. Congress left it to EPA to determine whether regulation of EGUs under section 112 is necessary. We believe it is reasonable to err on the side of regulation of such highly toxic pollutants in the face of uncertainty. Further, if we are unsure whether the other requirements of the CAA will address an identified hazard, it is reasonable to exercise our discretion in a manner that assures adequate protection of public health and the environment. Moreover, we must be particularly mindful of CAA regulations we include in our modeled estimates of future emissions if they are not

[62] 76 FR 24990.

final or are still subject to judicial review ([*e.g.*], the Transport Rule). If such rules are either not finalized or upheld by the Courts, the level of risk would potentially increase.

Id.

The CAA requires EPA to exercise its discretion in determining whether regulation under section 112 is necessary, and the D.C. Circuit has stated that ''there are many situations in which the use of the word 'necessary,' in context, means something that is done, regardless of whether it is indispensible, to achieve a particular end.'' *See Cellular Telecommunications & Internet Association, et al.* v. *FCC,* 330 F.3d 502, 510 (D.C. Cir. 2003). The EPA's interpretation of ''necessary'' is reasonable in the context of CAA section 112(n)(1)(A).

The commenter stated that EPA concedes that the Agency has not ''clearly established'' that regulation of HAP emissions under CAA section 112 is ''indispensible.'' The EPA has conceded nothing but, more importantly, the supposed standard that the commenter presents for evaluating whether it is necessary to regulate HAP emissions from EGUs is not required by the statute. Even the limited legislative history on which the commenter incorrectly relies does not espouse such a standard. The commenter specifically takes issue with EPA's statement that the Agency may find it is necessary to regulate EGUs under CAA section 112 if we are ''uncertain whether imposition of the other requirements of the CAA will sufficiently address the identified hazards.'' 76 FR at 24990. The commenter has again misinterpreted the Agency's position by stating that ''EPA construes CAA section 112(n)(1)(A) as permitting it to find that it is ''necessary'' to regulate EGUs even where the Agency does not actually know whether it is ''necessary'' to regulate EGUs.'' Instead, the EPA maintains that it may be necessary to regulate EGUs under CAA section 112 if we identify a hazard to public health or the environment that is appropriate to regulate today and our projections into the future do not clearly establish that the imposition of the requirements of the CAA will address the identified hazard in the future. Making a prediction about future emission reductions from a source category is difficult for statutory provisions that do not mandate direct control of the given source category or pollutants of concern. We maintain that erring on the side of caution is appropriate when the protection of public health and the environment from HAP emissions is not assured based on our modeling of future emissions.

Furthermore, as we stated in the preamble to the proposed rule, we believe it would be reasonable to find it appropriate *and* necessary to regulate EGUs under section 112 today based on a determination that HAP emissions from EGUs pose a hazard to public health and the environment without considering future HAP emission reductions. 76 FR 24991, n.14. We maintain this is reasonable because ''Congress could not have contemplated in 1990 that EPA would have failed in 2011 to have regulated HAP emissions from EGU's where hazards to public health and the environment remain.'' *Id.* The phrase ''after imposition of the requirements of [the Act]'' as contemplated CAA section 112(n)(1)(A) could be read to apply only to those requirements clearly and directly applicable to EGUs under the 1990 CAA amendments, all of which have been implemented and still hazards to public health and the environment from HAP emissions from EGUs remain.

g. Listing EGUs Under 112

Comment: One commenter stated that even if EPA were to establish under CAA section 112(n)(1)(A) that it is ''appropriate and necessary'' to regulate HAP emissions from EGUs, regulating those emissions in the form of a MACT standard established pursuant to CAA section 112(d) is contrary to the plain language of the Act. According to the commenter, if EPA proceeds to finalize the proposal and adopts such a standard, the rule will for this reason alone be ''dead-on-arrival''. According to the commenter, the EPA apparently believes that its only option in regulating EGU HAP emissions is establishing a MACT standard under CAA section 112(d). In the preamble to its proposal, the commenter states that EPA contends that, ''once the appropriate and necessary finding is made,'' EGUs are then ''subject to section 112 in the same manner as other sources of HAP emissions''—*i.e.,* by ''listing'' EGUs under CAA section 112(c) and adopting a MACT standard under CAA section 112(d). *See* 76 FR 24993/2 (emphasis added). The commenter further stated that, given that Congress ''directed the Agency to regulate utilities 'under this section' [*i.e.,* CAA section 112],'' EPA continues, it follows that ''EGUs should be regulated in the same manner as other categories for which the statute requires regulation.'' Id. (emphasis added). The commenter asserts that as EPA sees it, because ''Congress did not exempt EGUs from the other requirements of section 112,'' once EGUs were ''listed'' under CAA section 112(c), the Agency was ''required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d).'' Id. at 24,993/3 (emphasis added).

The commenter stated that, in support of this reading of the CAA, the EPA invokes the decision of the U.S. Court of Appeals for the D.C. Circuit in *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). The commenter further alleged that, according to EPA, the D.C. Circuit has ''already held that section 112(n)(1) 'governs how the Administrator decides whether to list EGUs.' '' *See* 76 FR 24993/2–3, quoting 517 F.3d at 583. The commenter stated that EPA construes that holding as indicating that, ''once listed, EGUs are subject to the requirements of section 112''—including, the EPA presumes, CAA section 112(d). Id. The commenter stated that elsewhere, the EPA construes CAA section 112(n)(1) (A) as ''govern[ing] how the Administrator decides whether to list EGUs for regulation under section 112,'' and quotes the D.C. Circuit's observation in *New Jersey* that ''Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs.'' *See* 76 FR 24981/2, quoting 517 F.2d at 582.

The commenter asserts that EPA misinterprets the ''under this section'' language of CAA section 112(n)(1); overstates the significance of the *New Jersey* decision; and, as a consequence, misapprehends the scope of its own discretion to formulate regulatory standards for EGUs under CAA section 112. In light of these errors, the commenter maintains that EPA should withdraw the proposed MACT rule.

One commenter stated that if Congress had intended that EPA regulate EGU HAP emissions only through a MACT standard, Congress could have—and presumably would have—directed the Agency to regulate EGU emissions ''under CAA section 112(d).'' Thus, the commenter maintained that EPA's authority to regulate EGU HAP emissions is not derived from any particular subsection of CAA section 112. Rather, the commenter stated that EPA is authorized to regulate ''under this section''—*i.e.,* CAA section 112 generally—as may be ''appropriate and necessary.'' The commenter stated that there is nothing on the face of CAA section 112(n)(1)(A) that specifies that regulation of EGUs must occur under CAA section 112(d). To the contrary, according to the commenter, a plain reading of CAA section 112(n)(1)(A), as interpreted based on the Oxley statement, indicates that establishing a

MACT standard for EGUs under CAA section 112(d) is not what Congress had in mind at all.

Response: We do not agree with the commenter. The EPA interpreted CAA section 112(n)(1)(A) in a manner that gives meaning to all the words used in the provision. *See NRDC* v. *EPA,* 489 F.3d 1364, 1373 (D.C. Cir. 2007) (admonishing EPA for an interpretation of CAA section 112(c)(9) that ignored certain words and the context in which they were used. The Court stated that ''EPA's interpretation would make the words redundant and one of them 'mere surplusage,' which is inconsistent with a court's duty to give meaning to each word used by Congress.'') (*citing TRW Inc.* v. *Andrews, 534 U.S. 19, 31, 122 S. Ct. 441, 151 L. Ed. 2d 339 (2001)).* Specifically, in the preamble to the proposed rule, we stated:

> The statute directs the Agency to regulate EGUs under section 112 if the Agency finds such regulation is appropriate and necessary. Once the appropriate and necessary finding is made, EGUs are subject to section 112 in the same manner as other sources of HAP emissions. Section 112(n)(1)(A) provision provides, in part, that: '[t]he 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 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.*

In the first sentence, Congress described the study and directed the Agency to evaluate the hazards to public health posed by HAP emissions listed *under subsection* (b) (*i.e.,* CAA section 112(b)). The last sentence requires the Agency to regulate *under this section* (*i.e.,* CAA section 112) if the Agency finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph (i.e., CAA section 112(n)(1)(A)). The use of the terms ''section'', ''subsection'', and ''subparagraph'' demonstrates that Congress was consciously distinguishing the various provisions of CAA section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs if the Agency finds it appropriate and necessary to do so. Congress directed the Agency to regulate utilities ''under this section,'' and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation. *See* 76 FR 24993.

We maintain that our interpretation of the statute gives meaning to all the words, and the commenter's interpretation does not give any particular meaning to the requirement to ''regulate under this section [112]''. The commenter is correct that Congress could have in CAA section 112(n)(1)(A) directed EPA to regulate HAP from EGUs under CAA section 112(d) after making the appropriate and necessary finding, but the commenter presumes too much when it stated that Congress would have directed the Agency to regulate HAP emissions from EGUs in such a manner if that is what Congress wanted, simply by including the phrase ''regulate under this paragraph'' or ''regulate under this subparagraph'' instead of directing the Agency to ''regulate under this section''. It did not do so.

As we explained in the section II.A. of the proposed rule, CAA section 112 establishes a mechanism to list and regulate stationary sources of HAP emissions. 76 FR 24980–81. Regulation under CAA section 112 generally requires listing under CAA section 112(c), regulation under CAA section 112(d), and, for sources subjected to MACT standards, residual risk regulations under CAA section 112(f) (as necessary to protect human health and the environment with an ample margin of safety). A determination that EGUs should be listed once the prerequisite appropriate and necessary finding is made is wholly consistent with the language of section 112(n)(1)(A), and listed sources must be regulated under CAA section 112(d). *See* CAA section 112(c)(2); *see also New Jersey*, 517 F.3d at 583 (112(n)(1)(A) ''governs how the Administrator decides whether to list EGUs'').

As noted above, Congress used the terms section, subsection, and subparagraph in section 112(n)(1)(A). The use of these three terms demonstrates that Congress was consciously distinguishing between the various provisions of section 112. Congress directed the Agency to regulate utilities ''under this section,'' and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation.

Furthermore, the flaws in the commenter's interpretation are highlighted by other CAA section 112 provisions wherein Congress provided specific direction as to the manner of regulation. For example, CAA section 112(m)(6) requires the Administrator to determine ''whether the other provisions of *this section* [112] are adequate'' and also indicates that ''[a]ny requirements promulgated pursuant to this *paragraph* * * * shall only apply to the coastal waters of the States which are subject to [section 328 of the CAA].'' (*emphasis added*).

In addition, CAA section 112(n)(3) provides that when the Agency is ''promulgating any standard under this section [112] applicable to publicly owned treatment works, the Administrator may provide for control measures that include pretreatment of discharges causing emissions of hazardous air pollutants and process or product substitutions or limitations that may be effective in reducing such emissions.'' Finally, CAA section 112(n)(5) directs the Agency to assess hydrogen sulfide emissions from oil and gas extraction and ''develop and implement a control strategy for emissions of hydrogen sulfide to protect human health and the environment * * * *using authorities under [the CAA] including [section 111] of this title and this section [112].*'' (*emphasis added*). We believe these provisions provide ample evidence that Congress knew how to alter or caveat regulation under CAA section 112 when that was its intent. For these reasons, we believe commenter's argument is without merit.

Comment: Two commenters stated that CAA section 112(n)(1)(A) does not specify that regulation of EGUs must proceed under CAA section 112(d). According to the commenter, an argument could be made, therefore, that the CAA accords EPA with the discretion to regulate EGUs using strategies other than emission standards in CAA section 112(d). The commenters also state that section 112(n)(1)(A) of the CAA requires that EPA ''develop and describe'' alternative control strategies for emissions which may warrant regulation under CAA section 112. According to the commenters if Congress meant for EPA to have one sole regulatory option, i.e., regulation of EGUs only under CAA section 112(d), then the development of alternative control strategies would be rendered meaningless because under CAA section 112(d)(3), the EPA is required to determine the level of control that is achieved by the best performing existing units for which it has data and then to impose that level of control on all existing units. The commenter further states that the development of ''alternative control strategies'' has no role to play in this process. One commenter does note that the consideration of ''alternative'' controls becomes relevant, if at all, only in those circumstances where EPA might seek to establish a ''Beyond-the-Floor'' MACT standard pursuant to CAA section 112(d)(2).

Response: The commenters are correct that CAA section 112(n)(1)(A) directed the Agency to develop and describe in the Utility Study report to Congress alternative control strategies for HAP emissions from EGUs that may warrant regulation in the Utility Study, but the commenters' interpretation of and conclusion based on that language are both factually and legally inaccurate.

The commenters appear to interpret the word ''alternative control strategies'' to mean something other than the traditional control technologies and control measures that are used to control HAP emissions from EGUs. We do not believe that is a reasonable interpretation of the statute, and the Agency did not interpret the statute in that manner when it conducted the Utility Study. In Chapter 13 of the Utility Study, the EPA considered a range of control measures that would reduce the different types of HAP emitted from EGUs. *http://www.epa.gov/ttn/atw/combust/utiltox/eurtc1.pdf*. The EPA considered pre-combustion controls such as coal washing, fuel switching, and gasification; combustion controls such as boiler design; post-combustion controls such as fabric filters, scrubbers, and carbon absorption; and alternative controls strategies such as demand-side management, energy conservation, and use of alternative fuels (*e.g.*, biomass) or renewable energy. The options discussed in the Utility Study for controlling HAP emissions from EGUs are almost universally available to comply with a CAA section 112(d) standard.

Given the manner in which the Agency conducted the Utility Study, the EPA interpreted the statutory direction as a requirement to set forth the potential alternative control options available to EGUs to comply with CAA section 112 standards in the event the Agency determined regulation under section 112 was appropriate and necessary. The EPA's development and discussion in the Utility Study of alternative control strategies for complying with the standards would help prepare EGUs to comply with the standards if promulgated. Thus, the EPA interpreted the direction to address control strategies in the Utility Study as a request to identify the controls available to EGUs for addressing HAP emissions, and such information would, of course, be relevant if EPA determined that such emissions warranted regulation under section 112.

Furthermore, the EPA establishes CAA section 112(d) standards for stationary sources and it is the responsibility of the sources to comply with the standards using any mechanism available, including pre-combustion and post-combustion measures. Also, the establishment of a MACT standard under CAA section 112(d)(2) and (3) is a two-step process. In the first step, the Agency establishes a floor based on the performance of the best controlled unit or units. *See* CAA section 112(d)(3). In the second step, the Agency must consider additional measures that may reduce HAP emissions and adopt such measures if reasonable after considering costs and non-air quality health and environmental effects. *See* CAA section 112(d)(2). Under the second step, the Agency can consider any measure that reduces HAP emissions even if no source in the category is employing the option under consideration. So, even under the commenter's flawed interpretation of ''alternative control strategies'', the direction in CAA section 112(n)(1)(A) is not a ''pointless exercise'' for the development of CAA section 112(d) standards as the Agency considers relevant technologies and HAP emission reduction approaches in evaluating whether to set a more stringent beyond the floor standard.

Comment: One commenter points to CAA section 307(d)(1)(C) and notes that CAA section 112(n) is listed among the provision for which the rulemaking requirements of CAA 307(d) apply. Commenter maintains that this inclusion creates an expectation under the statute that EPA may establish regulatory standards under CAA 112(n). The commenter points to CAA sections 112 (n)(1), (n)(3), and (n)(5) and states that those provisions specifically discuss regulation under CAA section 112 and that EPA must explain why CAA 307(d)(1)(C) states ''any regulation under'' CAA 112(n) to defend regulation of utilities under section 112(d). The commenter then implies that EPA erred by not even mentioning this provision at proposal.

The commenter also takes issue with EPA's statement in the proposed rule that ''use of the terms section, subsection, and subparagraph'' ''demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs,'' if EPA determines that it is appropriate and necessary to regulate EGUs. See 76 FR at 24,993/2.

One commenter does not agree with the EPA's finding that the word ''subsection'' in the first sentence of CAA section 112(n)(1)(A) demonstrates that Congress was consciously distinguishing between the various provisions of CAA section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs,'' were the EPA to ''find[ ] it appropriate and necessary to do so.'' *See* 76 FR 24993/2. According to the commenter, the only evident reason that the word ''subsection'' is used in the first sentence of CAA section 112(n)(1)(A) is because the reference is made to the ''pollutants'' which the Utility Study is to address—*i.e.*, the ''pollutants'' that are emitted by EGUs and which are ''listed under subsection (b)'' of CAA section 112. Similarly, the word ''subparagraph'' is used in the last sentence of CAA section 112(n)(1)(A) to identify ''the study'' which the EPA is directed to undertake by subparagraph (A) of CAA section 112(n)(1)—*i.e.*, the Utility Study. That the last sentence of subparagraph (n)(1)(A) also states that EPA ''shall regulate electric utility steam generating units under this section'' does not even imply—much less expressly communicate—that regulation ''under this section'' must mean ''regulation under section 112(d).'' The commenter stated that Congress was ''consciously distinguishing'' between the ''various provisions of section 112'' for the sake of clarity in the drafting of CAA section 112(n).

The commenter also asserts that the EPA mistakenly relies on section 112(c)(6) when the EPA states that '' 'where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly. Congress did not exempt EGUs from the other requirements of section 112,' '' and thus the Agency is '' 'required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)' '' (citing 76 FR at 24,993 (internal quotation omitted)).

According to the commenter, nothing in section 112(c)(6) indicates how (or even whether) EGU HAP emissions should be regulated under section 112; paragraph (c)(6) serves only to reiterate that the regulation of such emissions is to occur (if at all) as is provided by section 112(n)(1). The commenter also asserts that the EPA mistakenly relies on *New Jersey.* According to the commenter, the D.C. Circuit in that case did not indicate that the language of section 112(c)(6) should, or could, be construed to mean that EGUs must be regulated under a MACT standard adopted pursuant to section 112(d).

Response: The commenter makes a number of arguments that appear to take issue with the EPA's determination that EGUs should be regulated under CAA section 112(d) if the Agency determines that regulation of HAP emissions from such units is appropriate and necessary.

The commenter implies that the EPA erred because alternative mechanisms for regulation of EGUs under CAA section 112 might exist. We do not agree.

The commenter's argument that the EPA erred because we did not explain why section CAA section 307(d)(1)(C) contemplates regulations under CAA section 112(n) is without merit. It is correct that the Agency believes EGUs should be regulated in the same manner as other sources if the appropriate and necessary finding is made because of the structure of CAA section 112. Nothing in CAA section 112(n)(1) requires or implies that the Agency should or must establish standards for EGUs under that provision. Furthermore, unlike CAA sections 112(n)(3) and 112(n)(5) that commenter cites, CAA section 112(n)(1)(A) does not provide any guidance concerning the manner in which EPA is authorized or required to regulate sources under CAA section 112. *See* CAA section 112(n)(3) (specifically authorizing identified control measures and other requirements for consideration in issuing standards under CAA section 112); see also CAA section 112(n)(5) (directing the Agency to develop and implement a control strategy for emissions of hydrogen sulfide using any authority available under the CAA, including sections 112 and 111, if regulation is appropriate). For these reasons, we disagree that any error occurred because we did not specifically discuss in this proposed rule whether we could or should regulate EGUs under CAA section 112(n)(1) instead of CAA section 112(d).[63] The Agency validly listed EGUs in 2000 and listed sources must be regulated pursuant to CAA section 112(d).

Even if we agreed that regulation under CAA section 112(n)(1) was a viable option for EGUs, we would still have listed and regulated EGUs like other sources because CAA section 112(d) provides a statutory framework for regulating HAP emissions from sources and CAA section 112(n)(1) does not. We believe that even if CAA section 112(n)(1) were available to regulate EGUs, there would be sufficient uncertainty about the legal vulnerability of such an approach to caution against employing it. This legal uncertainty would be particularly troubling in light of the fact that we have identified hazards to public health and the environment from HAP emissions from EGUs that warrant regulation, and these regulations are long overdue.

The commenter also takes issue with our statement in the preamble to the proposed rule that the use of the words ''section'', ''subsection'', and ''subparagraph'' in CAA section 112(n)(1)(A) ''demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs.'' *See* 76 FR 24993. The commenter appears to make much of our use of the word ''must'' in that sentence and also states that our interpretation of the significance of the use of the three terms in CAA section 112(n)(1)(A) is flawed because Congress only used the three terms for purposes of clarity. The commenter is incorrect on both points. With respect to the commenter's concern regarding the use of the word ''must'' in the sentence quoted above, we note that in the next sentence we stated that ''Congress directed the Agency to regulate utilities 'under this section,' and accordingly EGUs *should* be regulated in the same manner as other categories for which the statute requires regulation.'' Id. (*emphasis added*). We were not foreclosing the possibility of any alternative interpretation and our use of the term ''must'' should not detract from the point we were trying to make. Specifically, we believe that Congress would have directed us to regulate EGUs under CAA section 112(n)(1)(A) if that was its intent and, absent that mandate, the better reading of the statute is the one provided in the preamble to the proposed rule, which is that EGUs should be listed pursuant to CAA section 112(c) and subject to CAA section 112(d) emission standards.

The commenter also stated that the EPA relied on CAA section 112(c)(6) to support a conclusion that EGUs must be regulated under CAA section 112(d). The commenter takes the EPA's statements out of context. The statement in whole read:

> Furthermore, the D.C. Circuit Court has already held that section 112(n)(1) ''governs how the Administrator decides whether to list EGUs'' and that once listed, EGUs are subject to the requirements of CAA section 112. *New Jersey*, 517 F.3d at 583. Indeed, the D.C. Circuit Court expressly noted that ''where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly,'' noting that ''section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants.'' *Id.* Congress did not exempt EGUs from the other requirements of CAA section 112, and once listed, EPA is required to establish emission standards for EGUs consistent with the requirements set forth in CAA section 112(d), as described below. *See* 76 FR 24993.

As can be seen from this passage, the Court cited section 112(c)(6) as an example of Congress' intent regarding regulating EGUs under CAA section 112. The commenter cited the last clause of the last sentence of the paragraph quoted above without including the prefatory clause ''once listed,'' and, without that clause, the statement is not fairly characterized. The point the EPA was making in that paragraph is that EGUs are a listed source category and listed sources must be regulated under CAA section 112(d) unless the EPA delists the source category.

Comment: One commenter stated that EPA overstates the significance of the D.C. Circuit's holding in *New Jersey* by suggesting that the decision mandates EGU regulation under CAA section 112(d) because EGUs ''remain listed'' under CAA section 112(c), *See New Jersey*, 517 F.3d at 582. According to the commenter, the court declined to address the lawfulness of EPA's having ''listed'' EGUs under CAA section 112(c), leaving that matter to be decided if and when EPA adopted standards for EGUs under CAA section 112. Nowhere in the decision did the D.C. Circuit indicate that EPA must regulate EGUs under CAA section 112(d).

According to the commenter, the EPA must consider both whether the regulation of EGUs is ''appropriate and necessary'' under section 112(n)(1) and address anew whether the Agency is authorized by section 112 to list EGUs under section 112(c) at all. The commenter asserts that on the face of the proposal, the EPA has not revisited the question whether the ''listing'' of EGUs under section 112(c) is consistent with congressional intent.

Response: The commenter's arguments are circular and it is difficult to fully determine exactly what its issue is with EPA's listing; however, it appears that the commenter believes that EPA incorrectly relied on the *New Jersey* decision to justify the listing of EGUs. The commenter also appears to argue that the Agency has never explained why it has the authority to list EGUs at all. We disagree.

As stated in the preamble to the proposed rule, CAA section 112(n)(1)(A)

[63] We note that in our January 2004 proposed rule, we solicited comment on whether section 112(n)(1)(A) provided independent authority to regulate EGUs. We received several comments on this issue, and we rejected the concept after reviewing the comments and further considering the language of section 112(n)(1)(A) and the structure of section 112. As such, we proposed and are finalizing that once the Agency determines that it is appropriate and necessary to regulate EGUs under section 112, those sources are listed pursuant to subsection 112(c), as we did in December 2000, and the Agency must set standards for those sources pursuant to section 112(d). See section 112(c) and (d)(1) (requiring establishment of 112(d) standards for listed source categories).

requires EPA to conduct a study of HAP emissions from EGUs and regulate EGUs under CAA section 112 if we determine that regulation is appropriate and necessary, after considering the results of the study. 76 FR 24981, 24986, and 24998. The only condition precedent to regulating EGUs under CAA section 112 is a finding that such regulation is appropriate and necessary (after conducting and considering the Utility Study), and once that finding is made the Agency has the authority to list EGUs under CAA section 112(c) as the first step in the process of establishing regulations under section 112. The D.C. Circuit agrees with that interpretation of the statute as evidenced by its statement in *New Jersey* that ''section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under section 112,'' 517 F.3d at 582, and the Court's statement directly contradicts the commenter's position.

The EPA did not rely on the *New Jersey* decision to justify the appropriate and necessary finding as the commenter suggests. We based the finding in 2000 on the extensive information available to the Agency at the time, and we confirmed the finding in the preamble to the proposed rule based on new information. The commenter had ample opportunity to comment on the appropriate and necessary finding, and it may challenge the basis of the listing (*i.e.* the appropriate and necessary finding) when EPA issues the final standards.

Comment: One commenter believes that the D.C. Circuit will condemn the final rule as a result of EPA's ''misapprehension'' that upon making an ''appropriate and necessary'' finding, the Agency is compelled by the CAA to adopt a regulatory standard for EGUs under CAA section 112(d). According to the commenter, a regulation will be invalid if the regulation '' 'was not based on the [agency's] own judgment' '' but '' 'rather on the unjustified assumption that it was Congress' judgment that such [a regulation] is desirable' or required.'' *See Transitional Hospitals Corp.* v. *Shalala*, 222 F.3d 1019, 1029 (D.C. Cir. 2000), quoting *Prill* v. *NLRB*, 755 F.2d 941, 948 (D.C. Cir. 1985). The commenter further notes that the D.C. Circuit has held that, where an agency wrongly construes a judicial decision as compelling a particular statutory interpretation, and thereby unduly limits the scope of its own discretion, the agency's action cannot be sustained. *See*, *e.g.*, *Phillips Petroleum Co.* v. *FERC*, 792 F.2d 1165, 1171 (D.C. Cir. 1986). The commenter believes the rule is bound to be rejected and that the EPA should ''reconsider the legal interpretations on which it purports to base its rule.''

Response: We do not agree that we have improperly interpreted the statute as limiting our discretion in the manner suggested by the commenter. The commenter makes only one specific allegation in this comment and that concerns the Agency's conclusion that it must establish CAA section 112(d) standards for EGUs in light of the *New Jersey* decision. The commenter does not explain why that conclusion is incorrect. As we state above and in the preamble to the proposed rule, because EGUs are a CAA section 112(c) listed source category, the Agency must establish CAA section 112(d) standards or delist EGUs pursuant to CAA section 112(c)(9). *See New Jersey*, 517 F.3d at 582–83 (holding that EGUs remain listed under section 112(c)); *see also* CAA section 112(c)(2) (requiring the Agency to ''establish emission standards under subsection [112] (d)'' for listed source categories and subcategories); 76 FR 24998–99. We concluded in the preamble to the proposed rule that we could not delist EGUs because our appropriate and necessary analysis showed that EGUs did not satisfy the CAA section 112(c)(9)(B)(i) delisting criteria. *Id.* We did not address in the preamble to the proposed rule whether EGUs satisfied the CAA section 112(c)(9)(B)(ii) criteria because EGUs failed the first prong of the delisting provisions. *Id.* We reach the same conclusion in the final rule and also address the delisting petition submitted by this commenter. Because we cannot delist EGUs, we must regulate them under CAA section 112(d). The commenter has provided no legitimate argument to rebut this conclusion. *See also* previous responses regarding regulation under section 112(n)(1)(A).

Comment: One commenter alleges that EPA impermissibly relied on CAA section 112(c)(9) to interpret ''hazards to public health'', and argues that the ''residual risk'' provisions in CAA section 112(f)(2) are more appropriate for the establishment of standards for EGUs. The commenter stated that by using CAA section 112(c)(9)(B)(i) in defining ''hazards to public health'', the Agency has seized on the one interpretation of the phrase that is surely contrary to congressional intent and, thus, falls outside the permissible range of its interpretative discretion. The commenter maintains that the ''delisting'' criteria of CAA section 112(c)(9) are simply irrelevant to the decision whether EGU HAP emissions will present any ''hazards to public health'' sufficient to warrant regulation of those emissions under CAA section 112.

The commenter also argues that Congress intended that EGUs be treated differently from all other ''major sources'' to which the ''delisting'' provisions of CAA section 112(c)(9), and the standard-setting provisions of CAA section 112(d) necessarily and automatically apply. Therefore, according to the commenter, the EPA's proposal to utilize the criteria of CAA section 112(c)(9) to inform its findings under CAA section 112(n)(1)(A) treats EGUs exactly the same as all other major source categories, is contrary to congressional intent, and thus unlawful. The commenter goes on to state that in exercising its discretion to define ''hazards to public health'' as the phrase is used in CAA section 112(n)(1)(A), the EPA would be better served to consider the ''residual health risk'' provisions of CAA section 112(f)(2). Those provisions provide a better analogy to the establishment of standards for EGUs under CAA section 112 than do the ''de-listing'' criteria of CAA section 112(c)(9).

The commenter believes the category-specific criteria of paragraph (c)(9) are a poor fit for an evaluation of ''hazards to public health'' that should reasonably include such factors as the affected population, the characteristics of exposure, the nature of the health effects, and the uncertainties associated with the data. The commenter states that, while CAA section 112(n)(1)(A) does not expressly include any requirement that EGU emissions be regulated with an ''ample margin of safety,'' that standard is more appropriate than the ''one-in-a-million'' cancer risk standard of CAA section 112(c)(9)(B)(i) that EPA proposes to employ.

Response: The commenter acknowledges that EPA has broad discretion to interpret the phrase ''hazard to public health'' but argues that the one thing we cannot do is use the CAA section 112(c)(9)(B) delisting provisions as a benchmark in making that interpretation. The commenter asserts that the use of the delisting standard is clearly contrary to Congressional intent but it does not provide any substantive rebuttal to our conclusion that the CAA section 112(c)(9) standards reflects the level of hazard which Congress concluded warranted continued regulation. Instead, the commenter reverted to its argument that the statute treated EGUs differently. The EPA views the disparate treatment of EGUs in a different light than commenter. While it is true that Congress established a different statutory provision governing whether to add EGUs as a regulated source category under section 112, we do not interpret CAA section 112(n)(1)(A) as providing Congressional license to ignore risks that Congress determined warranted regulation for all other source categories. Because CAA section 112(c)(9) defines that level of risk, it is reasonable to consider it when evaluating whether EGU HAP emissions pose hazards to public health.

The commenter also suggests that the ''ample margin of safety standard'' of CAA section 112(f)(2) is a better fit than the one-in-a-million standard set forth in CAA section 112(c)(9)(B)(1) for evaluating hazards to public health. The commenter asserts that an evaluation of ''hazards to public health'' should include such factors as the affected population, the characteristics of exposure, the nature of the health effects, and the uncertainties associated with the data. However, the EPA did not rely solely on the delisting provisions for evaluating hazards to public health as commenter suggests. In fact, the EPA considered all of the factors the commenter suggests in making our finding.[64] Thus, we decline to adjust our approach to evaluating hazards to public health and the environment based on the comments.

h. 2000 Finding (and 2005 Delisting)

Comment: Several commenters generally support EPA's 2000 finding that regulating HAP emissions from EGUs under CAA section 112 is ''appropriate and necessary.'' According to the commenters, the 2000 finding was proper under the CAA and within EPA's discretion, well-supported based on sound science available to the Agency at the time on the harm from HAP emitted by EGUs, and no additional information makes the finding invalid. Several commenters cited the conclusions of the Utility Study[65] and Mercury Study,[66] which they assert supported the finding and satisfied the only prerequisite for the finding. One commenter specifically asserted that the 2000 finding was well-supported by the Utility Study's conclusions that (1) there was a link between anthropogenic Hg emissions and MeHg found in freshwater fish, (2) Hg emissions from coal-fired utilities were expected to worsen by 2010, and (3) MeHg in fish presents a threat to public health from fish consumption. One commenter noted that the CAA does not require a conclusive link between HAP emissions and harm. One commenter stated that the CAA grants the Administrator discretion in her finding, and that discretionary decision should not be overly scrutinized, citing court opinion.[67] In support of the finding, one commenter stated that it would not make sense for Congress to limit HAP emissions from small businesses such as dry cleaners but to exempt U.S. EGUs, which are the largest sources of many HAP emissions. One commenter agreed that finding was further supported because numerous control options were available to reduce HAP emissions. One commenter agreed with the 2000 finding that the Agency lacked sufficient evidence to conclude that non-Hg HAP from EGUs posed no hazard.

The commenters who generally supported the 2000 finding also commented on specific aspects of the finding. Several commenters asserted that while the evidence on Hg alone supports the finding, the potential harm from non-Hg HAP further supported the 2000 finding. Several commenters noted that new science continues to support the 2000 finding. Several commenters also stated that the ''appropriate'' finding was further supported because numerous control options were available at the time of the finding that would reduce HAP emissions. One commenter concurred with EPA that regulating natural gas-fired EGUs was not appropriate and necessary because the impacts due to HAP emissions from such units are negligible based on the results of the Utility Study.

Several commenters addressed the 2005 reversal of the 2000 finding. Several commenters specifically supported the vacatur of the 2005 action. Other commenters asserted that the 2005 action was proper, and that EPA reverted back to the 2000 finding in the proposed rule without adequate explanation or support. Several commenters cited the 2005 action as invalidating the 2000 finding, specifically noting that EPA concluded that ''no hazards to public health'' remained after accounting for emission reductions under CAIR. These commenters assert that EPA's current position is illegal because EPA took the exact opposite position on the interpretation of the term ''necessary'' in its 2005 reversal, and, thus, deserves no judicial deference. One commenter stated that in 2005 EPA recognized the potential for excessive regulation created by CAA section 112 and determined that the 2000 finding lacked foundation.

Several commenters generally disagreed with the 2000 finding, with two commenters stating that EPA did not have a rational justification for it and another claiming that it was fraught with misinformation and overestimating assumptions. One commenter claimed that EPA did not explain the terms ''appropriate'' and ''necessary'' in the 2000 finding and that the emission control analysis was inadequate. Two commenters stated that the 2000 finding was based on data that was more than 10 years old, which causes serious concern regarding the validity of the findings because technology, the regulatory environment, and the economic climate have evolved. Furthermore, because the Utility Report underestimated emissions controls that EGUs would install by 2010 and additional controls that would be later required by the CSAPR, the basis for EPA's 2000 finding has changed. Several commenters stated that a ''plausible link'' between anthropogenic Hg and MeHg in fish is not an adequate reason for the 2000 finding. Several commenters claim that EPA only identified health concerns for Hg (and potentially Ni) but not other HAP from coal-fired EGUs in the 2000 finding, and, thus, cannot regulate HAP other than Hg because the 2000 finding authorizes only the regulation of Hg. One commenter questioned the Hg emissions underlying the 2000 finding, specifically the fraction of total deposition attributable to U.S. EGUS and the fact that EPA projected an increase in U.S. EGU emissions from 1990 to 2010 though emissions actually declined.

Several commenters raised procedural issues related to the 2000 finding. Several commenters stated that the 2000 finding failed to provide public notice and comment. According to the commenters, the CAA requires that any decision made under CAA section 112(n) must go through public notice and comment. The commenters further stated that the failure to provide public notice and comment means that this MACT is outside EPA's statutory authority. One commenter stated that because the 2000 finding was never ''fully ventilated'' in front of the D.C. Circuit, the EPA's authority to regulate EGUs under CAA section 112(d) is directly at issue. The commenters claim that specific issues did not undergo

[64] 76 FR 24992.

[65] U.S. EPA 1998. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress. EPA–453/R–98–004a. February.

[66] U.S. EPA, 1997.

[67] ''Where a statute is precautionary in nature, the evidence difficult to come by, uncertain, or conflicting because it is on the frontiers of scientific knowledge, the regulations designed to protect the public health, and the decision that of an expert administrator, [courts] will not demand rigorous step-by-step proof of cause and effect.'' *Ethyl Corp.* v. *EPA*, 541 F.2d 1, 28 (Ct. App. D.C. Circ. 1978).

public notice and comment, including least-cost regulatory options, the impact of regulation on electricity reliability, and EPA's interpretation of the requirements under CAA section 112(n)(1)(A). One commenter claims that EPA attempted to provide after-the-fact support for its 2000 finding with new legal analysis and new factual information, contrary to *New Jersey* v. *EPA* that held that EPA may not revisit its 2000 finding except through delisting under CAA section 112(c)(9). One commenter stated that EPA's 2000 finding should be reviewed when EPA issues the actual NESHAP.[68] One commenter stated that the 2000 finding ignored EO 12866.

Response: EPA agrees with the commenters that the 2000 finding was reasonable and disagrees with the commenters asserting that the 2000 finding was unreasonable or failed to follow proper procedural requirements.

The EPA agrees that reviewing courts defer to the reasoned scientific and technical decisions of an Agency charged with implementing complex statutory provisions such as those at issue in this case. As EPA stated in the preamble to the proposed rule, the EPA maintains that the 2000 finding was reasonable and based on well-supported evidence available at the time, including the Utility Study, the Mercury Study,[69] and the NAS study,[70] which all showed the hazards to public health and the environment from HAP emitted from EGUs. New technical analyses conducted by EPA confirm that it remains appropriate and necessary to regulate HAP emissions from EGUs. Furthermore, the EPA agrees with the commenters on several points raised, specifically that EGUs were and remain the largest anthropogenic source of several HAP in the U.S., that risk assessments supporting the 2000 finding indicated potential concern for several non-Hg HAP, and that several available control options would effectively reduce HAP emissions from U.S. EGUs.

The EPA agrees with the commenters that Congress did not exempt EGUs from section 112(d) HAP emission limits while simultaneously limiting emissions at other sources with less HAP emissions. Congress simply provided EPA with a separate path for listing EGUs by requiring that the Agency evaluate HAP emissions from EGUs and determine whether regulation under CAA section 112 was appropriate and necessary. Since 1990, the EPA has promulgated regulations requiring the use of available control technology and other practices to reduce HAP emissions for more than 170 source categories. U.S. EGUs are the most significant source of HAP in the country that remains unaddressed by Congress's air toxics program. The EPA listed EGUs in 2000 because the considerable amount of available data supported the conclusion that regulation of EGUs under CAA section 112 was appropriate and necessary. That finding was valid at the time, and EPA reasonably added EGUs to the CAA section 112(c) list of sources that must be regulated under CAA section 112.

The EPA acknowledges that we did not expressly define the terms appropriate and necessary in the 2000 finding, but the finding is instructive in that it shows that EPA considered whether HAP emissions from EGUs posed a hazard to public health and the environment and whether there were control strategies available to reduce HAP emissions from EGUs when determining whether it was appropriate to regulated EGUs.[71] When concluding it was necessary, the Agency stated that imposition of the requirements of the Act would not address the identified hazards to public health or environment from HAP emissions and that section 112 was the proper authority to address HAP emissions.[72] The EPA explained in the preamble to the proposed rule its conclusion that the 2000 finding was fully supported by the information available at the time,[73] and EPA stands by the conclusions in that notice. Furthermore, the EPA provided an interpretation of the terms appropriate and necessary that is wholly consistent with the 2000 finding. The EPA does not agree with the commenters that a quantification of emissions reductions or a specific identification of the available controls was necessary to support the 2000 finding and listing. The EPA considered the Utility Study when making the finding, and that study clearly articulated the various alternative control strategies that EGUs could employ to control HAP emissions.[74] As to emission reductions, the EPA cannot estimate the level of HAP emission reductions until the Agency proposes a CAA section 112(d) standard after a source category is listed.

The EPA disagrees with commenters that suggest it was not ''rational'' to determine that it was appropriate to regulate HAP emissions from EGUs due to the cancer risks identified in the Utility Study or the potential concerns associated with other HAP emissions from EGUs. Nothing in CAA section 112(n)(1)(A) suggests that EPA must determine that every HAP emitted by EGUs poses a hazard to public health or the environment before EPA can find it appropriate to regulate EGUs under CAA section 112. In fact, the EPA maintains that it must find it appropriate and necessary to regulate EGUs under CAA section 112 if it determines that any one HAP emitted from EGUs poses a hazard to public health or the environment that will not be addressed through imposition of the requirements of the Act. The EPA disputes the commenters' conclusion that the 2000 finding was limited to Hg and Ni emissions, but, even if it were, the EPA reasonably concluded that EGUs should be listed pursuant to CAA section 112(c) based on the Hg and Ni finding. As stated in the 2000 finding, cancer risks from some non-Hg metal HAP (including As, Cr, Ni, and Cd) were not low enough to be to eliminate as potential concern.[75] Source categories listed for regulation under CAA section 112(c) must be regulated under CAA section 112(d), and the D.C. Circuit has stated that EPA has a ''clear statutory obligation to set emission standards for each listed HAP''. *See Sierra Club* v. *EPA*, 479 F.3d 875, 883 (D.C. Cir. 2007), *quoting National Lime Association* v. *EPA*, 233 F.3d 625, 634 (D.C. Cir. 2000). Therefore, even if EPA concluded that CAA section 112(n)(1) authorized a different approach for regulating HAP emissions from EGUs, the chosen course which is supported by the CAA (*i.e.*, listing under CAA section 112(c)) requires the Agency to regulate under CAA section 112(d) consistent with the statute and case law interpreting that provision.

The EPA disagrees that there is any concern regarding the validity of the 2000 finding or that the emissions information provided in the 2000 finding makes the finding ''questionable'' as stated by some of the commenters. The EPA maintains that the 2000 finding was sound and fully supported by the record available at the time, including the future year emissions projections. Therefore, the listing of EGUs is valid based on that finding alone. Even though Hg emissions have decreased since the 2000 finding instead of increasing as projected, the new technical analyses confirm that Hg emissions from EGUs continue to pose hazards to public

[68] *See UARG* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001).

[69] U.S. EPA, 1997.

[70] NAS, 2000.

[71] 65 FR 79830.

[72] *Id.*

[73] 65 FR 24994–24996.

[74] *See* Chapter 13 of the Utility Study (U.S. EPA, 1998).

[75] 76 FR 79827.

health and the environment. The EPA also indicated potential concern for several non-Hg HAP in the 2000 finding. It is well established that even small amounts of HAP can cause significant harm to human health and the environment.

The EPA agrees with the commenters who assert that the 2005 action was in error and disagrees with the commenters that the 2005 action invalidated the 2000 finding. As fully described in the preamble to the proposal, the EPA erred in the 2005 action by concluding that the 2000 finding lacked foundation. The 2005 action improperly conflated the ''appropriate'' and ''necessary'' analyses by addressing the ''after imposition of the requirements of the Act'' in the appropriate finding as well as the necessary finding. The EPA also indicated that it was not reasonable to interpret the necessary prong of the finding as a requirement to scour the CAA for alternative authorities to regulate HAP emissions from stationary sources, including EGUs, when Congress provided section 112 for that purpose. The EPA asserts that the 2000 finding was sound and fully supported by the record available at the time for all the reasons stated in this final rule and the proposed rule. The 2005 action interpreted the statute in a manner inconsistent with the 2000 finding and attempted to delist EGUs without complying with the mandates of CAA section 112(c)(9)(B). *See New Jersey*, 517 F.3d at 583 (vacating the 2005 ''delisting'' action). In the preamble to the proposed rule, the EPA set forth a revised interpretation of CAA section 112(n)(1) that is consistent with the statute and the 2000 finding. The EPA also explained in the preamble to the proposed rule why the 2005 action was not technically or scientifically sound. The EPA specifically addressed the errors associated with the 2005 action in the preamble to the proposed rule, and commenters' assertions do not cause us to revisit these issues. The commenter is also incorrect in suggesting that a change in interpretation is per se invalid and provided no support for that position. *See National Cable & Telecommunications Ass'n, et al.,* v. *Brand X Internet Services, et al.,* 545 U.S. 967, 981 (discussing the deference provided to an Agency changing interpretations, the Court stated ''change is not invalidating, since the whole point of *Chevron* deference is to leave the discretion provided by ambiguities of a statute with the implementing Agency.'') (Internal citations and quotations omitted).

The EPA disagrees with the commenters who raise concerns about the validity of the 2000 finding because the data on which that finding was based were more than 10 years old. The EPA made the finding at that time based on the scientific and technical information available, and the finding is wholly supported by that information. In addition, even though not required to do so, the EPA has since conducted new technical analyses utilizing the best information available in 2010 as several years have passed since the 2000 finding. These new analyses confirm that HAP emissions from EGUs continue to pose a hazard to public health and the environment, even after taking into account emission reductions that have occurred since 2000 from promulgated rules, settlements, and consent decrees. *See* 76 FR 24991.

Contrary to the commenter's assertion, the EPA did not violate CAA section 307(d) by not providing a notice and comment opportunity before making the December 2000 appropriate and necessary finding. One commenter challenged EPA's 2000 finding and listing on the same grounds, and the D.C. Circuit dismissed the case because CAA section 112(e)(4) clearly states that listing decisions cannot be challenged until the Agency issues final emission standards for the listed source category. *See UARG* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001). The EPA has provided the public an opportunity to comment on both the 2000 finding and the 2011 analyses that support the appropriate and necessary determination as part of the proposed rule, and anyone may challenge the listing in the D.C. Circuit in conjunction with a challenge to this final rule. The commenters could have also commented on the CAA section 112(n)(1) (*e.g.*, the Utility Study and the Mercury Study) studies in 2000 as they were included in the docket, but EPA is not aware of any comments on those studies. In any case, these studies were peer reviewed and considered the best information available at that time. The EPA has fully complied with the rulemaking requirements of CAA section 307(d).

The EPA also disagrees with the commenters' characterization of the *New Jersey* case. The D.C. Circuit did not say, as one commenter suggested, that EPA is not able to consider additional information that is collected after the 2000 finding; instead, the Court stated that EPA could not revise its appropriate and necessary finding and remove EGUs from the CAA section 112(c) list without complying with the delisting provisions of CAA section 112(c)(9). *See New Jersey*, 517 F.3d at 582–83. The EPA also disagrees with the commenter's assertion that EPA disregarded EO 12866 when making the 2000 finding. As stated in the Federal Register notice, the 2000 finding did not impose regulatory requirements or costs and was reviewed by the Office of Management and Budget (OMB) in accordance with the EO.[76]

2. New Technical Analyses

a. General Comments on New Technical Analyses

Comment: Several commenters stated that the new analyses, including the risk assessments and technology assessments, confirm that it remains appropriate and necessary to regulate U.S. EGU HAP under CAA section 112. These commenters stated that the new analyses provide even more support than the risk and technology information available at the time the 2000 finding was made, including information on further developed emissions control technology, proven and cost-effective control of acid gases using trona and dry sorbent injection, stabilized natural gas prices that makes fuel switching and switching dispatch to underutilized combined cycle plants more feasible, more information on ecosystem impacts from HAP, ''hotspots'' from the deposition of Hg around EGUs, the potential for re-emission of Hg, updated emissions data and future projections of HAP emissions, and modern air pollution modeling tools. One commenter states affordable control technology has been in use in this sector for 10 to 40 years, and studies on EGU-attributable Hg hazard has undergone two in-depth EPA reviews, as well as a review by the NAS. Several commenters claimed that regulating U.S. EGUs is appropriate and necessary to protect public health based on information provided in the new technical analyses. These commenters acknowledged the substantial reductions in HAP from recent regulations and new studies that confirm serious health risks from HAP exposure. One commenter stated that new studies show higher risks to fetuses than previously estimated, increasing the potential for neurodevelopmental effects in newborns. One commenter noted that EGUs are a major source of HAP, including HCl, HF, As, antimony, Cr, Ni, and selenium, all of which adversely affect human health. The commenter stated that because of these health effects, the EPA has ample evidence to support a determination

[76] 65 FR 79831.

that non-Hg HAP emissions present a risk to human health.

Other commenters disagreed that the new analyses confirm that it remains appropriate and necessary to regulate U.S. EGUs. One commenter claims that EPA tried to use the new technical analyses to provide retroactive justification for the 2000 finding, which only found ''plausible links'' of health effects and ''potential concerns'' of health effects of certain metal emissions, dioxins and acid based aerosols. The commenter also asserted that none of these new analyses demonstrate that EGU regulation under section 112 is necessary and appropriate.

One commenter agreed that EPA may supplement its finding with new information, analyses and arguments to reaffirm the 2000 finding up until EPA issues final emissions standards. The commenter noted that the CAA does not freeze the finding. However, another commenter argued that EPA does not have the authority to rely on new technical analyses because the CAA requires EPA to make the finding on the basis of the Utility Study alone. According to that commenter, the EPA unreasonably stretched the language of CAA section 112 by considering new technical analyses.

Citing a report from Dr. Willie Soon that was submitted to the SAB, one commenter stated that the new technical analyses supporting the proposed rule do not conform to the Information Quality Act, which requires that information relied on by EPA be accurate, reliable, unbiased, and presented in a complete and unbiased manner.

Response: The EPA agrees with the commenters that state that the new technical analyses (*e.g.*, the risk assessments and technology assessment) confirm the 2000 finding and disagrees with the commenters that state otherwise. The EPA also agrees with the commenters that the 2000 finding was valid at the time it was made based on the CAA section 112(n)(1) studies and other information available to the Agency at that time. Furthermore, the EPA agrees with commenters that the final rule will lead to substantial reductions in HAP emissions from EGUs, that control of the HAP is estimated to lead to public health and environmental benefits as discussed in the RIA, that Hg emissions from U.S. EGUs pose a hazard to public health, and that non-Hg HAP emissions from EGUs pose a hazard to public health.

Although these new analyses were not required, the EPA agrees with the commenters that stated that EPA is authorized to conduct additional analyses to confirm the 2000 finding. The EPA disagrees with the commenter's assertion that the Agency is not authorized to consider new information and at the same time unable to use the information available in 2000 because, according to the commenter, that information is ''stale.'' Under this theory, the Agency could not ever make an appropriate and necessary finding prospectively, thereby excusing the Agency from its obligations to protect public health and the environment because it did not diligently act in undertaking its statutory responsibility to establish CAA section 112(d) standards within two years of listing EGUs. *See* CAA section 112(c)(5). This is an illogical result that finds no basis in the statute. The EPA also disagrees with the commenter's assertion that EPA may not consider new analyses conducted after the Utility Study in determining whether it is appropriate and necessary to regulate EGUs under section 112 for the reasons set forth in the preamble to the proposed rule.[77]

The EPA disagrees with the commenter's implication that EPA conducted the new analyses because of alleged flaws in the 2000 finding. As explained in detail in the preamble to the proposed rule, the 2000 finding was wholly valid and reasonable based on the information available to the Agency at that time, including the Utility Study. Further, the EPA maintains that had it complied with the statutory mandate to issue CAA section 112(d) standards within two years of listing EGUs, the EPA would likely have declined to conduct new analyses. The EPA conducted new analyses because over 10 years had passed since the 2000 finding, and EPA wanted to evaluate HAP emissions from U.S. EGUs based on the most accurate information available, though the Agency was not required to reevaluate the 2000 finding. In conducting the new analyses, the EPA used this updated information to further support the finding.

The EPA strongly disagrees with the commenter that stated that EPA failed to conform to the Information Quality Act. The EPA used peer reviewed information and quality-assured data in all aspects of the technical analyses used to support the appropriate and necessary finding supporting this regulation. In addition, the EPA submitted the Hg Risk TSD to the SAB for peer review, which ''supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs.'' [78] The SAB received the comments from Dr. Willie Soon, and had those comments available for consideration in their deliberations regarding the Hg risk analysis. The SAB specifically supported elements of the analysis criticized by Dr. Willie Soon regarding the use of the EPA RfD as a benchmark for risk and the connection between Hg emissions from U.S. EGUs and MeHg concentrations in fish. In addition, the risk assessment methodology for the non-Hg case studies is consistent with the methodology that EPA uses for assessments performed for Risk and Technology Review rulemakings, which underwent peer review by the SAB in 2009. [79] During the public comment period, the EPA also completed a letter peer review of the methods used to develop inhalation cancer risk estimates for Cr and Ni compounds, and those reviews were generally supportive. See above description of this peer review. For the final rulemaking, the EPA revised both risk assessments consistent with recommendations from the peer reviewers. The EPA relies on the SAB's review of the quality of the information supporting the analytical results. Accordingly, contrary to the commenters' assertions, the EPA acted consistently with the Information Quality Act as well as EPA's and OMB's peer review requirements.

b. Hg Emissions Estimates

1. Hg Emissions From EGUs

Comment: The commenters addressed the 2005 and 2016 emissions estimates for Hg and expressed concern that inaccuracies in these emissions estimates result in overestimates of risks from Hg deposition. Further, commenters compared EPA's 2010 estimate and 2016 estimate, and stated that it is not possible for 29 tons to be a correct inventory total for Hg emissions in both years given expected reductions from CSAPR. In addition, commenters specifically commented on assumptions included in the Integrated Planning Modeling (IPM), including a concern that Hg speciation factors used by IPM overestimate emissions in 2016. Other commenters noted that EGU sources are the predominant source of U.S. anthropogenic Hg emissions, particularly the oxidized and particulate forms of Hg that are of primary concern for Hg deposition.

Response: The EPA disagrees with commenters' assertions that the EPA's

[77] 76 FR 24988.

[78] U.S. EPA–SAB, 2011.

[79] U.S. EPA–SAB, 2010.

emissions estimates overestimate risk. While EPA agrees that the 2005 Hg emissions may be overestimated, such an overestimate in 2005 would actually lead to an underestimate of risk in 2016 and not an overestimate of risk, as claimed by the commenter, because the ratio approach used by EPA to scale fish tissue data would underestimate risk if 2005 Hg estimates were overestimated. Since the 2005 emissions are not used as a starting point for 2016 emissions from IPM, any 2005 overestimate does not affect the 2016 emissions levels. The 2016 emissions are computed by IPM based on forecasts of demand, fuel type, Hg content of the fuel, and the emissions reductions resulting from each unit's configurations. *See* IPM Documentation for further information, which is available in the docket. No commenter has provided any evidence that the IPM 2016 emissions projection methodology resulted in an overestimate.

The EPA acknowledges that the current Hg emissions estimate would not be the same as the 2016 Hg emissions estimate given that compliance with CSAPR is anticipated to have some Hg co-benefits. For this reason, the EPA reflected emission reductions anticipated from CSAPR in the Hg deposition modeling for 2016 in the Hg Risk TSD. In the final rule, the EPA revised the estimate of Hg emissions remaining from U.S. EGUs in 2016, which includes additional emission reductions anticipated from the final CSAPR. The revised estimate shows that U.S. EGUs would emit 27 tons of Hg in 2016. Although EPA does not use the current Hg emissions estimates in any of the risk calculations, the EPA estimates that current Hg emissions are 29 tons. Conclusions about the trend between current emissions and emissions in 2016 are limited by the fact that different methods were used to compute the two estimates, as fully explained in the revised Emissions Overview memo in the docket.

The EPA disagrees with the commenter's assertion that incorrect Hg emission factors result in incorrect 2016 emissions. The 2016 projected Hg emissions are not based on emissions factors. The 2016 Hg emissions are computed by the IPM based on forecasts of demand, fuel type, Hg content of the fuel, and the emissions reductions resulting from each unit's configurations. The speciation factors referenced by the commenter provide a basis for the speciation of total projected Hg emissions into particulate, divalent gaseous, and elemental species, and do not impact the total amount of Hg emissions.

The EPA agrees with commenters who noted that EGU sources are the predominant source of U.S. anthropogenic Hg emissions, and in particular the oxidized and particulate forms of Hg that are of primary concern for Hg deposition.

2. Global Hg Emissions

Comment: Several commenters stated that predicted Hg deposition relies heavily on the amount of gaseous elemental Hg used to define the boundary and initial conditions of a model, e.g., the Hg that enters the U.S. from outside the U.S. boundaries. The commenters asserted that this is especially important because Hg emissions from Asia—the region immediately upwind of North America that affects U.S. Hg deposition significantly and also affects it the most compared to other regions—are expected to continue to increase.[80] [81] [82] [83] [84] [85] According to the commenter, this would affect the amount of Hg in the boundary and initial conditions. The commenters claim that EPA's modeling did not account for these emission changes, thus leading to an overestimate of U.S. EGU-attributable deposition in 2016.

Several commenters noted that Hg emissions from U.S. EGUs are small when compared to global Hg emissions totals and natural sources within the U.S. These commenters used a variety of information to support alternative conclusions about the necessity to control U.S. EGU emissions to reduce Hg risk: global Hg emissions inventories, global and regional photochemical modeling research, and observation-based assessments. A commenter stated that EPA has not acknowledged the dramatic decline in Hg emissions from U.S. EGUs since the late 1990s (approximately 50 percent) to the current level or consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources, natural (such as fires) and human-caused.

Response: The EPA disagrees that boundary and initial conditions used in modeling Hg deposition need adjustment for several reasons. First, the EPA does not use the first 10 days of the modeling simulation in the analysis, which is more than sufficient to remove the influence of initial conditions on Hg deposition estimates.[86] Second, it is difficult to accurately characterize the speciation of Hg that flows into the U.S. from other countries due to the lack of data near the boundaries of the modeling domain. Third, the boundary inflow for the CMAQ Hg modeling used in the Hg deposition modeling are based on a global model GEOS–CHEM simulation using a 2000 based global inventory.[87] A recently published comparison of global Hg emissions by continent for 2000 and 2006 found that total Hg emissions from Asia (and Oceania) total 1,306 Mg/yr in 2000 and 1,317 Mg/yr in 2006.[88] The EPA has determined that because the Asian Hg emissions estimated in this study are nearly constant between 2005 and 2006, any adjustments to the boundary conditions or adjustments to modeled Hg deposition would be invalid and inappropriate. Recent research has shown that ambient Hg concentrations have been decreasing in the northern hemisphere since 2000.[89] Because emissions from Asia have not appreciably changed between 2000 and 2006 and ambient Hg concentrations have been decreasing, ENVIRON's analysis contains incorrect assumptions and we need not address them further. For these reasons and the large uncertainties surrounding projected Hg

[80] Jaffe D., Prestbo E., Swartzendruber P., Weiss-Penzias P., Kato S., Takami A., Hatakeyama S., Kajii Y., 2005. ''Export of Atmospheric Mercury From Asia,'' *Atmospheric Environment*, 39, 3029–3038.

[81] Jaffe D., Strode S., 2008. ''Fate and Transport of Atmospheric Mercury From Asia,'' *Environmental Chemistry*, 5, 121.

[82] Pacyna E.G., Pacyna J.M., Sundseth K., Munthe J., Kindbom K., Wilson S., Steenhuisen F., Maxson P., 2010. ''Global Emission of Mercury to the Atmosphere From Anthropogenic Sources in 2005 and Projections to 2020,'' *Atmospheric Environment*, 44, 2487–2499.

[83] Pirrone N., Cinnirella S., Feng X., Finkelman R.B., Friedli H.R., Leaner J., Mason R., Mukherjee A.B., Stracher G.B., Streets D. G., Telmer K., 2010. ''Global Mercury Emissions to the Atmosphere From Anthropogenic and Natural Sources,'' *Atmospheric Chemistry and Physics*, 10, 5951–5964.

[84] Streets, D.G., Zhang, Q., Wu, Y., 2009. ''Projections of Global Mercury Emissions in 2050.'' *Environmental Science & Technology* 43, 2983–2988.

[85] Weiss-Penzias P., Jaffe D., Swartzendruber P., Dennison J.B., Chand D., Hafner W., Prestbo E., 2006. ''Observations of Asian Air Pollution in the Free Troposphere at Mt. Bachelor Observatory in the Spring of 2004,'' *Journal of Geophysical Research*, 110, D10304.

[86] Pongprueksa, P., Lin, C.J., Lindberg, SE., Jang, C., Braverman, T., Bullock, O.R., Ho, T.C., Chu, H.W., 2008. ''Scientific Uncertainties in Atmospheric Mercury Models III: Boundary and Initial Conditions, Model Grid Resolution, and Hg (II) Reduction Mechanism.'' *Atmospheric Environment* 42, 1828–1845.

[87] Selin, NE., Jacob, D.J., Park, R.J., Yantosca, R.M., Strode, S., Jaegle, L., Jaffe, D. 2007. ''Chemical Cycling and Deposition of Atmospheric Mercury: Global Constraints From Observations.'' *Journal of Geophysical Research-Atmospheres* 112.

[88] Streets *et al.,* 2009.

[89] Slemr, F., Brunke, E.G., Ebinghaus, R., Kuss, J., 2011. ''Worldwide Trend of Atmospheric Mercury Since 1995.'' *Atmospheric Chemistry and Physics* 11, 4779–4787.

global inventories, the EPA concludes that the most appropriate technical choice is to keep the Hg boundary conditions the same between the 2005 and 2016 simulations.

The EPA also disagrees with the commenters' assertion that EPA has not acknowledged the decline in Hg emissions for the U.S. EGUs since the late 1990s. The EPA analyzed historical, current, and future projected Hg emissions from the power generation sector, as cited in the preamble to the proposed rule. The EPA also disagrees with the commenters' assertions that EPA failed to consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources. As noted in the Hg Risk TSD, the EPA modeled Hg emissions from U.S. and non-U.S. anthropogenic and natural sources to estimate Hg deposition across the country. The EPA also determined the contribution of Hg emissions from U.S. EGUs to total Hg deposition in the U.S. by running modeling simulations for 2005 and 2016 with Hg emissions from U.S. EGUs set to zero. Based on the Hg Risk TSD, Hg emissions from U.S. EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition.

The commenters suggest that Hg emissions from U.S. EGUs represent a limited portion of the total Hg emitted worldwide, including anthropogenic and natural sources. While EPA acknowledges that Hg emissions from U.S. EGUs are a small fraction of the total Hg emitted globally, it views the environmental significance of Hg emissions from U.S. EGUs and other domestic sources as a more germane consideration. Mercury is emitted from EGUs in three forms. Each form of Hg has specific physical and chemical properties that determine how far it travels in the atmosphere before depositing to the landscape. Although gaseous oxidized Hg and particle-bound Hg are generally local/regional Hg deposition concerns, all forms of Hg may deposit to local or regional watersheds. U.S. coal-fired power plants account for over half of the U.S. controllable emissions of the quickly depositing forms of Hg. Although emissions from international Hg sources contribute to Hg deposition in the U.S., the peer reviewed scientific literature shows that Hg emissions from U.S. EGUs in the U.S. significantly enhance Hg deposition and the response of ecosystems in the U.S. [90] [91] [92] [93]

c. Hg Deposition Modeling

1. General Comments on Deposition Modeling

Comment: Several commenters stated that according to the ENVIRON report, the EPA overestimated U.S. EGU-attributable Hg deposition by 10 percent on average (and up to 41 percent in some areas). The commenters claim this overestimation is the result of boundary condition treatment, the exclusion of U.S. fire emissions,[94] and Hg plume chemistry approach. In addition, one commenter referenced the same ENVIRON report and stated that before implementation of controls required by the proposed rule, areas with relatively high EGU-attributable Hg deposition (one-fifth or more of total deposition) in 2016 constitute less than 0.25 percent of the continental U.S. area, and only three grid cells have EGU contributions exceeding half of total deposition.

Another commenter suggested that current research shows that models of Hg atmospheric fate and transport overestimate the local and regional impacts of some anthropogenic sources, such as U.S. EGUs. Thus, according to the commenter, calculated contributions to Hg deposition and fish tissue MeHg levels from these sources represent upper bounds of actual contributions,[95] [96] and EPA should present results as estimates of lower and upper bound limits.

Response: The EPA disagrees with the information presented by ENVIRON. The ENVIRON report is based on the misapplication of multiple incommensurate modeling studies and false premises which include the incorrect notion that the boundary conditions are over-estimated and the idea that EPA should use in-plume chemistry that has not been explicitly characterized and peer reviewed. Reactions that may reduce gas phase oxidized Hg in plumes have not been explicitly identified in literature. Recent studies in central Wisconsin and central California suggest the opposite may happen; elemental Hg may be oxidized to Hg(II) in plumes.[97] [98] Better field study measurements and specific reaction mechanisms need to be identified before making conclusions about potential Hg in-plume chemistry or applying surrogate reactions in regulatory modeling. The possibility that Hg(0) is oxidized to Hg(II) in plumes suggests coal-fired power plant Hg contribution inside the U.S. may be underestimated in EPA modeling.

The EPA asserts that the numbers suggested by the commenter are inaccurate, as it is not appropriate to adjust EPA's deposition estimates based on previous Hg modeling done with older Hg chemistry, in-plume reactions that have not been explicitly identified, and erroneous adjustments to Hg boundary inflow. Recent research has shown that ambient Hg concentrations have been decreasing in the northern hemisphere since 2000.[99] The EPA declines to revise this analysis as commenter suggests for several reasons, including available evidence indicates that emissions from China have not appreciably changed between 2000 and 2006 [100] and ambient Hg concentrations have decreased, the commenter inappropriately comingled out–of-date Hg modeling simulations with EPA results, and ENVIRON's analysis has not undergone any scientific peer review and presents information with incorrect assumptions as noted in this response.

The EPA also disagrees with the commenter's interpretation of the applicability of wildfire Hg emissions to

[90] Caffrey *et al.,* 2010.

[91] Driscoll, C. T., Han, Y.-J., Chen, C. Y., Evers, D. C., Lambert, K. F., Holsen, T. M., *et al.,* (2007). ''Mercury Contamination in Forest and Freshwater Ecosystems in the Northeastern United States.'' *BioScience*, 57(1).

[92] Keeler, G.J., Landis, M.S., Norris, G.A., Christianson, E.M., Dvonch, J.T., 2006. ''Sources of Mercury Wet Deposition in Eastern Ohio, USA.'' *Environmental Science & Technology* 40, 5874–5881.

[93] White, E.M., Keeler, G.J., Landis, M.S., 2009. ''Spatial Variability of Mercury Wet Deposition in Eastern Ohio: Summertime Meteorological Case Study Analysis of Local Source Influences.'' *Environmental Science & Technology* 43, 4946–4953.

[94] Finley, B.D., Swartzendruber, P.C., Jaffe, D.A., 2009. ''Particulate Mercury Emissions in Regional Wildfire Plumes Observed at the Mount Bachelor Observatory.'' *Atmospheric Environment* 43, 6074–6083.

[95] Seigneur, C., Lohman, K., Vijayaraghavan, K., Shia, R.L., 2003. ''Contributions of global and regional sources to mercury deposition in New York State.'' Environmental Pollution 123, 365–373.

[96] Seigneur, C., Vijayaraghavan, K., Lohman, K., Karamchandani, P., Scott, C., 2004. ''Modeling the atmospheric fate and transport of mercury over North America: power plant emission scenarios.'' *Fuel Processing Technology* 85, 441–450.

[97] Kolker, A., Olson, M.L., Krabbenhoft, D.P., Tate, M.T., Engle, M.A., 2010. ''Patterns of mercury dispersion from local and regional emission sources, rural Central Wisconsin, USA.'' *Atmospheric Chemistry and Physics* 10, 4467–4476.

[98] Rothenberg, SE., McKee, L., Gilbreath, A., Yee, D., Connor, M., Fu, X.W., 2010. ''Wet deposition of mercury within the vicinity of a cement plant before and during cement plant maintenance.'' *Atmospheric Environment* 44, 1255–1262.

[99] Slemr *et al.,* 2011.

[100] Streets *et al.,* 2009.

[101] Finley *et al.,* 2009.

this assessment. Finley *et al.,* (2009) [101] suggests caution when using their field data to make assumptions about Hg(p) emissions from wildfires; the estimated particulate Hg emissions from wildfires is based on one field site with a limited sample size, and the assumptions made (such as the observed Hg(p) to carbon monoxide ratios at this location) may not be valid on a broader scale.[102] Mercury emissions from wildfires are a re-volatilization of previously deposited Hg.[103] Given that electrical generating power plants are currently and historically have been among the largest Hg-emitting sources, the inclusion of wildfire emissions in a modeling assessment would necessarily increase the contribution from this emissions sector.

The EPA disagrees with the assertion that EPA failed to consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources and disagrees with the interpretation of EGU deposition presented in the ENVIRON report. As noted in the Hg Risk TSD, the EPA modeled Hg emissions from U.S. and non-U.S. anthropogenic and natural sources to estimate Hg deposition across the country. The EPA also determined the contribution of Hg emissions from U.S. EGUs to total Hg deposition in the U.S. by running modeling simulations for 2005 and 2016 with Hg emissions from U.S. EGUs set to zero. Hg emissions from U.S. EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. The ENVIRON report provides no risk analysis of EGU contribution.

The EPA disagrees that research [104,105] presented by the commenter shows that U.S. EGU impacts are over-estimated. The commenter's references do not support this statement. The references provided by the commenter are based on Hg modeling that uses models that are no longer applied and that are based on out-dated Hg chemistry and deposition assumptions. Given the advances in Hg modeling since the early 2000s, the EPA does not believe an upper and lower bound estimate is necessary.

[100] Streets *et al.,* 2009.

[101] Finley *et al.,* 2009.

[102] *Id.*

2. Chemical Reactions

Comment: Several commenters stated that the CMAQ modeling fails to account for the chemical reduction of gaseous ionic Hg to elemental Hg that may occur in EGU plumes. The commenters noted that EPA did not use the Electric Power Research Institute's (EPRI) Advanced Plume-in-Grid Treatment, which includes a surrogate reaction to reduce gaseous ionic Hg to elemental Hg inside plumes. Multiple commenters claimed that the reduction of reactive gaseous Hg to gaseous elemental Hg has been reported in power plant plumes and that supporting data include atmospheric concentrations of speciated Hg measured downwind of power plant stacks at ground-level monitor sites and dispersion model predictions.[106,107] A detailed description of various plume measurement studies is provided in EPRI Comments, Section 3.4: Plant Bowen, Georgia, Plant Pleasant, Wisconsin, and Plant Crist, Florida. One commenter believed the impact of grid resolution (12 km sized grid cells) on the CMAQ modeling was not appropriately addressed by EPA. Their concerns due to grid resolution include the notion that a source's emissions will be averaged over the entire grid cell. According to the commenter, such averaging causes an artificially fast dilution that smoothes out areas of high and low deposition, which may limit the ability of the model to simulate smaller areas of localized high deposition. This commenter believed that using the APT would address these issues.

Response: The EPA disagrees with the commenters' claims that oxidized Hg chemically reduces to elemental mercury within the plume. There is no evidence of these chemical reactions in the scientific literature. The references cited by the commenters are from non-peer reviewed reports and conference proceedings. The EPA does not consider information presented at conferences or industry reports to be peer reviewed literature, and consideration of oral presentation material would be inappropriate. Further, even these cited references do not provide sufficient information for incorporating the supposed reactions into the modeling (*e.g.*, specific chemical reactions, reaction rates, etc.); rather, the cited references only suggest that oxidized gas phase Hg could be reduced and postulate a possible pathway.

[103] Wiedinmyer, C., Friedli, H., 2007. ''Mercury emission estimates from fires: An initial inventory for the United States.'' *Environmental Science & Technology* 41, 8092–8098.

[104] Seigneur *et al.*, 2003.

[105] Seigneur *et al.*, 2004.

Recent studies in central Wisconsin and central California suggest the opposite may happen; elemental Hg may be oxidized to Hg(II) in plumes.[108,109] Better field study measurements and specific reaction mechanisms need to be identified before making conclusions about potential Hg in-plume chemistry or applying surrogate reactions in regulatory modeling. Currently, models such as Advanced Plume Treatment (APT) use a surrogate reaction for the potential reactive gas phase Hg reduction that may or may not occur in plumes.[110] Reactions that may reduce gas phase oxidized Hg in plumes have not been explicitly identified in literature. The application of potentially erroneous in-plume chemistry that is a fundamental component of APT would be inappropriate. In addition, the APT is not available in the most recent version of CMAQ. It would be inappropriate for EPA to apply an out of date photochemical model with in-plume chemistry that has not been shown to exist.

The EPA agrees with the commenter that the CMAQ modeling with 12 km grid resolution may provide a lower bound estimate on EGU contribution as higher impacts using finer grid resolution are possible. The commenter's assertion that EGU impacts are likely higher further supports the final conclusions of the exposure modeling assessment. The EPA notes that the application of a photochemical model at a 12 km grid resolution for the entire continental U.S. is more robust in terms of grid resolution and scale that anything published in literature and represents the most advanced modeling platform used for a national Hg deposition assessment.

3. Modeled Deposition Compared to Measured Deposition

Comment: Multiple commenters expressed dissatisfaction related to EPA's model performance evaluation of CMAQ estimated Hg deposition. The commenters stated that EPA failed to evaluate the CMAQ model against real-world measurements and that EPA fails to provide first-hand information on wet and dry deposition processes. The commenters also stated that EPA needs

[108] Kolker *et al.,* 2010.

[109] Rothenberg *et al.*, 2010.

[110] Vijayaraghavan, K., Seigneur, C., Karamchandani, P., Chen, S.Y., 2007. ''Development and application of a multipollutant model for atmospheric mercury deposition.'' *Journal of Applied Meteorology and Climatology* 46, 1341–1353.

to assess how predicted values of deposition compare to Mercury Deposition Network (MDN) data and how predicted values of ambient speciated Hg concentrations compare to measurement networks like AMNet and SEARCH. In addition, commenters stated that EPA used highly aggregated performance metrics comparing model estimates to observations that they believe result in a degraded and lenient operational evaluation of the modeling system. A commenter suggested that EPA's model performance provides no confidence for the intended purpose of estimating deposition near point sources. One commenter simply noted that EPA's model over-estimated total Hg wet deposition at MDN monitors. Finally, several commenters noted that EPA presented a negative modeled wet deposition total in the Air Quality Modeling TSD, which is physically impossible.

Response: EPA agrees with the commenters that the negative estimate for wet deposition in the Air Quality Modeling TSD was an error. This error reflected an incorrect calculation in the post-processing of model and observation pairs that only influenced the calculation of model performance metrics. The error has been fixed, and the model performance metrics in the revised Air Quality Modeling TSD have been updated. This error did not affect Hg deposition. In response to comments, the EPA provided additional model performance evaluation by season to the revised Air Quality Modeling TSD. In addition, in response to comments, the EPA also included model performance evaluation for total Hg wet deposition for the 36 km modeling domain in the revised Air Quality Modeling TSD.

The EPA disagrees that it did not conduct an assessment comparing CMAQ total Hg wet deposition estimates to MDN data. The Air Quality Modeling TSD clearly shows a comparison of CMAQ estimated total Hg wet deposition with MDN data for the entire length of the modeling period. The CMAQ wet deposition of Hg has been and will continue to be extensively evaluated against MDN sites.[111] There is no dry deposition monitoring network, which precludes evaluating CMAQ dry deposition processes. The EPA disagrees that an evaluation of ambient speciated Hg against routine monitor networks such as AMNet or SEARCH would be useful for this particular modeling application. The AMNet Hg network did not exist in 2005, which is EPA's baseline model simulation time period, and the SEARCH network started making preliminary measurements of Hg at one or two sites in 2005. In addition, measurement artifacts related to gaseous oxidized Hg are difficult to quantify and make direct comparison to model estimates problematic.[112] Considering the problems associated with TEKRAN measurements of ambient Hg and the sparse nature of routine measurements in the U.S., the EPA did not compare ambient Hg against model estimates.

The EPA disagrees that the model performance presented in the air quality TSD is insufficient. The EPA asserts that the model performance evaluation is generally similar to the level of model performance presented in literature. One commenter presented the results of several Hg modeling studies as providing information that the commenter believes to be relevant for this assessment in terms of model performance metric estimation and the level of model performance evaluation shown for assessments modeling Hg near point sources. For example, one cited study titled ''Modeling Mercury in Power Plant Plumes'' models near-source Hg chemistry from U.S. EGUs, but provides absolutely no information about model performance evaluation.[113]

Another commenter identified two studies as supposedly having Hg modeling results that are applicable to EPA's analysis.[114] [115] These studies present similar model performance metrics as EPA. The EPA disagrees that the Agency used ''highly aggregated performance metrics'' that result in degraded and lenient model evaluation. The studies presented [116] [117] as relevant for point source mercury modeling use an approach to aggregate the operational performance metrics across many monitor locations as did EPA; however, these articles calculate long term annual averages of modeled and observed total Hg wet deposition before estimating performance metrics. It is common practice to pair modeled estimates and observations in space and time (weekly in this case) and estimate performance metrics, then average all the metrics together. The latter is the approach taken by the EPA and should have been taken by the studies presented by the commenter. The EPA used a more stringent approach to match observations and predictions and aggregation of operational model performance. The EPA agrees that the commenter accurately restated total wet deposition model performance information provided by the EPA in the Air Quality Modeling TSD. To provide context, other Hg modeling studies show a positive bias for annual total Hg wet deposition.[118] [119] An annual Hg modeling application done by ENVIRON [120] and the Atmospheric and Environmental Research for Lake Michigan Air Directors Consortium show seasonal average normalized bias between 70 and 158 percent and seasonal average normalized error between 72 and 503 percent.[121] These results indicate a very large over-estimation tendency. The model performance shown by EPA is consistent with other long-term Hg modeling applications.

4. Excess Local Deposition From Hg Emissions From U.S. EGUs (Deposition Hotspots)

Comment: One commenter stated that reducing Hg will benefit local environments. The commenter stated that a 2007 study confirmed the presence of Hg ''hotspots'' downwind from coal-fired power plants and confirmed that coal-fired power plants within the U.S. are the primary source of Hg to the Great Lakes and the Chesapeake Bay.[122] The commenter also stated that the study is consistent with a major Hg deposition study conducted

[111] Bullock, O.R., Atkinson, D., Braverman, T., Civerolo, K., Dastoor, A., Davignon, D., Ku, J.Y., Lohman, K., Myers, T.C., Park, R.J., Seigneur, C., Selin, NE., Sistla, G., Vijayaraghavan, K., 2009. ''An analysis of simulated wet deposition of mercury from the North American Mercury Model Intercomparison Study.'' *Journal of Geophysical Research-Atmospheres* 114.

[112] Lyman, S.N., Jaffe, D.A., Gustin, M.S., 2010. ''Release of mercury halides from KCl denuders in the presence of ozone.'' *Atmospheric Chemistry and Physics* 10, 8197–8204.

[113] Lohman *et al.,* 2006.

[114] Seigneur, C., Lohman, K., Vijayaraghavan, K., Jansen, J., Levin, L., 2006. ''Modeling atmospheric mercury deposition in the vicinity of power plants.'' *Journal of the Air & Waste Management Association* 56, 743–751.

[115] Vijayaraghavan, K., Karamchandani, P., Seigneur, C., Balmori, R., Chen, S.–Y., 2008. ''Plume-in-grid modeling of atmospheric mercury.'' *Journal of Geophysical Research-Atmospheres* 113.

[116] Seigneur, C., Lohman, K., Vijayaraghavan, K., Jansen, J., Levin, L., 2006. ''Modeling atmospheric mercury deposition in the vicinity of power plants.'' *Journal of the Air & Waste Management Association* 56, 743–751.

[117] Vijayaraghavan, K., Karamchandani, P., Seigneur, C., Balmori, R., Chen, S.-Y., 2008. ''Plume-in-grid modeling of atmospheric mercury.'' *Journal of Geophysical Research-Atmospheres* 113.

[118] *Id.*

[119] Vijayaraghavan *et al.,* 2007.

[120] Yarwood, G, Lau, S., Jia, Y., Karamchandani, P., Vijayaraghavan, K. 2003. Final *Report: Modeling Atmospheric Mercury Chemistry and Deposition with CAMx for a 2002 Annual Simulation.* Prepared for Wisconsin Department of Natural Resources. *http://www.gypsymoth.wi.gov/air/toxics/mercury/hg_X97579601_appB.pdf.*

[121] Yarwood *et al.*, 2003.

[122] Evers, David C. *et al.,* 2007. ''Biological Mercury Hotspots in the Northeastern United States and Southeastern Canada,'' *Bioscience.* Vol. 57 No. 1. p. 29.

by the EPA and the University of Michigan that concluded that approximately 70 percent of Hg wet deposition resulted from local fossil fuel emissions in the region.[123]

One commenter agreed with the Agency's assessment of the potential for deposition ''hotspots'' that shows that Hg deposition near EGUs can be three times as large as the regional average. The commenter stated that this excess Hg deposition would substantially increase the health and environmental risks associated with emissions at these sites. The same commenter also stated that EPA applied a conservative methodology to quantify near-source Hg deposition. The commenter stated that maximum excess local Hg deposition may be significantly underestimated by averaging high deposition sites downwind of an EGU in the direction of prevailing winds with lower excess deposition at locations close to but frequently upwind of the facility. The same commenter suggests that had EPA used CMAQ and individual 12x12 km^2 grid cells to quantify local deposition, the model could increase the excess Hg deposition at these locations significantly and place them at even greater risk of adverse health and environmental effects of HAP from U.S. EGUs.

One commenter stated that the Hubbard Brook Research Foundation issued a report in 2007 that identified five Hg hotspots, one of which was in the Adirondack Park, along with four suspected hotspots.[124] The commenter stated that this study also provides a good description of the impacts of Hg on the Common Loon, which is a symbol of a healthy Adirondack environment.

One commenter stated that there is there is no evidence of Hg hotspots due to local deposition associated with coal-fired power plants. According to the commenter, the EPA's use of a 50 km radius to calculate hotspots is flawed. The commenter stated that modeling studies show that deposition of Hg emitted from power plants is not confined to a 50-km radius around the plants and that most emissions from power plants travel beyond 50 km.[125]

Several commenters stated that the EPA does not adequately define hotspots in this proposed rule. Those same commenters cited a previous EPA definition of hotspots as ''a waterbody that is a source of consumable fish with MeHg tissue concentrations, attributable solely to utilities, greater than EPA's MeHg water quality criterion of 0.3 mg/kg'' (milligrams per kilogram).[126] The same commenters stated that it is unclear why EPA changed from defining a hotspot by fish tissue MeHg concentration to defining a hotspot by depositional excess. Two commenters suggested that a Hg hotspot is a specific location that is characterized by elevated concentrations of Hg exceeding a well-established criterion, such as a reference concentration (RfC) when compared to its surroundings. Those same commenters stated that identifying Hg hotspots should not be constrained to locations where concentrations can be attributed to a single source or sector.[127] One of those two commenters noted that others have defined ''hotspots as a spatially large region in which environmental concentrations far exceed expected values, with such values (i.e. concentrations) being 2 to three standard deviations above the relevant mean.'' [128]

One commenter stated that Hg concentrations are not always highest at sites closest to a major source. The commenter referred to a study [129] that demonstrated that concentrations of atmospheric reactive gaseous Hg, gaseous elemental Hg, and fine particulate Hg were lower when measured 25 km from a 1,114 MW coal-fired EGU than when measured 100 km away. The commenter stated that these findings contradict the idea, implicit in EPA's hotspot analysis, that reactive gaseous Hg decreases with distance from a large point source.

One commenter provided information from a non-peer reviewed report with wet Hg deposition measurements downwind from the coal-fired power plant Crist in Pensacola, FL. The commenter stated that using the same data from these same wet deposition sites, one study [130] found that Hg wet deposition and concentrations did not differ in a statistically significant manner among these three sites and that the concentrations values were similar to those from Mercury Deposition Network (MDN) sites that are more than 50 km away from Plant Crist located along the Northern Gulf of Mexico coast.

Another commenter stated that Plant Crist installed a wet scrubber and has operated that scrubber continuously since December 2009. The commenter stated that the scrubber reduces total Hg emissions by about 70 percent and reduces emissions of reactive gaseous Hg by about 85 percent. The commenter cited a non-peer reviewed conference presentation [131] that reported changes in Hg wet deposition relative to historic measurements. The commenter stated that, taken collectively, these findings show that increased local total Hg deposition, possibly due to EGUs, and deposition changes due to changes in EGU emissions, are small.

Two commenters stated that a study by the Department of Energy (DOE) that collected and analyzed soil and vegetation samples for Hg near three U.S. coal-fired power plants—one in North Dakota, one in Illinois, and one in Texas—found no strong evidence of ''hotspots'' around these three plants.

Two commenters stated that analysis of long-term trends in Hg emissions from coal-fired EGUs and wet deposition in Florida concluded that statistical analysis does not show evidence of a significant relationship between temporal trends in Hg emissions from coal-fired EGUs in Florida and Hg concentrations in precipitation during 1998 to 2010.

Two commenters stated that the Hg Risk TSD presents no information, summary statistics, and/or actual calculations showing how excess deposition within 50 km of an EGU source is obtained. The commenters stated that by assessing only Hg deposition attributable to EGUs, the EPA fails to provide a context for all other sources of Hg deposition. The commenters stated that the Agency does not explain why deposition from the top 10 percent of EGU Hg emitters does not decline, despite substantial reductions in modeled Hg emissions from those sources between 2005 and 2016.

[123] Cohen, *et al.,* 2004. ''Modeling the Atmospheric Transport and Deposition of Mercury to the Great Lakes,'' *Environmental Research 95,* (247–265).

[124] Driscoll, C.T., D. Evers, K.F. Lambert, N. Kamman, T. Holsen, Y-J. Han, C. Chen, W. Goodale, T. Butler, T. Clair, and R. Munson. Mercury Matters: Linking Mercury Science with Public Policy inthe Northeastern United States. 2007. Hubbard Brook Research Foundation. Science Links Publication. Vol. 1, no. 3.

[125] Seigneur *et al.,* 2006.

[126] U.S. EPA, 2005. 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).* Final rule, March 29.

[127] Evers *et al.,* 2007.

[128] Sullivan T., 2005. ''The Impacts of Mercury Emissions from coal-fired Power Plants on Local Deposition and Human Health Risk.'' Presented at the Pennsylvania Mercury Rule Workgroup Meeting, October 28.

[129] Kolker, *et al.,* 2010.

[130] Caffrey, J.M., Landing, W.M., Nolek, S.D., Gosnell, K.J., Bagui, S.S., Bagui, S.C., 2010. ''Atmospheric deposition of mercury and major ions to the Pensacola (Florida) watershed: spatial, seasonal, and inter-annual variability.'' *Atmospheric Chemistry and Physics* 10, 5425–5434.

[131] Krishnamurthy N., Landing W.M, Caffrey J.M., 2011. ''Rainfall Deposition of Mercury and Other Trace Elements to the Northern Gulf of Mexico.'' Presented at the 10th International Conference on Mercury as a Global Pollutant, Halifax, Nova Scotia, Canada, July 27.

According to the commenters this implies that the top 10 percent EGUs may have approximately as much of a regional effect as a local effect.

Two commenters stated that the CMAQ model has limitations when used to predict local deposition and tends to overestimate local deposition. The commenters stated that modeling studies using either a plume model or an Eulerian model predict that 91 to 96 percent of the Hg emitted by an EGU travels beyond 50 km.[132]

Response: The EPA agrees with the commenters that stated that Hg emissions from EGUs deposit locally and regionally and contribute to excess local deposition near U.S. EGUs. The EPA acknowledges additional studies[133] cited by those commenters that corroborate EPA's conclusions. However, the EPA disagrees with those commenters' characterization of the methodology used to calculate the potential for excess local deposition. In response, the EPA has clarified the methodology in the new TSD entitled ''Technical Support Document: Potential for Excess Local Deposition of U.S. EGU Attributable Mercury in Areas near U.S. EGUs,'' which is available in the docket.

The EPA agrees that there is no generally agreed-upon definition of ''hotspot.'' As discussed in the preamble and TSD, for the purposes of the appropriate and necessary finding, the EPA determined that information on the potential for excess deposition of Hg in areas surrounding power plants would be useful in informing the finding. The EPA disagrees with some commenters who misinterpreted the intent of the Hg deposition hotspot analysis. Specifically, the analysis is not of ''Hg hotspots'', which are often defined as high Hg concentration in fish, but rather of Hg deposition hotspots, defined as excess local Hg deposition around U.S. EGUs, as clarified in the new Local Deposition TSD. Because EPA did not identify ''Hg hotspots'' of high Hg concentrations in fish, the EPA's MeHg water quality criterion of 0.3 mg/kg is irrelevant to EPA's analysis of excess local Hg deposition for this rule.

The EPA disagrees that the analysis assumes that deposition of Hg is confined to a 50-km radius around power plants. The purpose of the EPA's analysis was to evaluate whether there existed ''excess deposition of Hg in nearby locations within 50 km of EGUs that might result in Hg deposition 'hotspots'.'' As explained further in the new TSD, the EPA calculated the average EGU-attributable deposition (based on CMAQ modeling of Hg deposition) in the area 500 km around each plant and the average EGU-attributable deposition in the area 50 km around each plant. The difference between those two values is the excess local deposition around the plant. The EPA does not suggest Hg emissions from power plants stop at 50 km from the source. Some portion of EGU emissions deposit before 50 km, and some portion travels beyond 50 km. In addition, Hg disperses as it transports, so the average EGU contribution can be lower in areas beyond 50km relative to areas within 50km even though Hg emissions from EGUs are depositing into U.S. watersheds.

The EPA disagrees with some commenters' interpretation of the analysis as being focused on local deposition from all sources. In fact, the focus was on excess local deposition, rather than all local deposition. The EPA has clarified the purpose of the excess local deposition analysis in the new TSD. The EPA agrees that all EGUs add to local deposition, however, not all EGUs have local deposition that greatly exceeds regional deposition, which is the relevant question. The EPA disagrees that the DOE study referenced by the commenters attempted to assess the same analytical question as EPA's analysis. The DOE study focused on comparisons of total deposition near and far from power plants. The EPA's analysis did not focus on total Hg deposition, because as EPA acknowledges throughout its analysis, global sources of Hg deposition account for a large percentage of total Hg deposition. In addition, including global sources of Hg deposition would obscure the comparison of local and regional U.S. EGU-attributable Hg deposition. Because of regional deposition from both domestic and global sources of Hg, total Hg deposition at any location is unlikely to be highly correlated with local sources. The EPA's analysis focused on U.S. EGU-attributable Hg deposition and demonstrates that for some plants (especially those with high Hg emissions), there is local deposition of Hg that exceeds the average regional deposition around the plant.

The EPA's analysis shows heterogeneity in the amount of excess local deposition around plants. The new Local Deposition TSD shows that some plants can have local deposition that is less than the regional average deposition, suggesting that most of the Hg from those plants is transported regionally or that other EGUs in the vicinity of those plants dominate the deposition of Hg near the plants. This does not detract from the overall finding that around some power plants with high levels of Hg emissions excess local deposition is on average three times the regional EGU-attributable deposition around those plants.

The EPA disagrees that the Hg Risk TSD did not provide sufficient information regarding the excess local deposition calculation. Nonetheless, the EPA has further clarified the methodology in the new Local Deposition TSD, including further descriptions of the method used to calculate the local and regional deposition around power plants along with maps and tables of results.

The EPA disagrees with the commenters that stated that the discussion of local deposition in the Hg Risk TSD did not demonstrate that Hg deposition from the top 10 percent of EGU Hg emitters declines. Table 1 of the new Local Deposition TSD clearly shows that mean local deposition (within 50km of a plant) for the top 10 percent of emitters declines from 4.89 micrograms per cubic meter ($\mu g/m^3$) to 1.18 $\mu g/m^3$. What does not change is the percent local excess for EGU-attributable Hg deposition. This implies that while Hg deposition from EGUs is declining, there is still an excess contribution to local deposition relative to regional deposition; *e.g.*, because of dispersion, the contribution to average deposition outside 50 km from the plant is lower than the contribution to average deposition within 50 km of the plant.

The EPA disagrees that the information[134] provided by the commenter regarding the Crist plant and other coal-fired power plants in Florida is relevant to EPA's analysis of excess local deposition from U.S. EGUs because it is based on measurements of wet Hg deposition without consideration of dry Hg deposition, which can be a significant component of Hg deposition.

The EPA disagrees with the commenter regarding the interpretation of the literature related to the spatial extent of deposition of Hg emitted by U.S. EGUs. The EPA also disagrees that the peer-reviewed CMAQ model has limitations for this application or overestimates local deposition. The commenter does not provide any credible support for the assertion that grid-based models typically overestimate local deposition surrounding EGUs. The EPA maintains that the CMAQ photochemical model represents the best science currently available in simulating atmospheric

[132] Edgerton *et al.,* 2006.

[133] Driscoll *et al.,* 2007.

[134] EPRI, 2010.

chemistry, transport, and deposition processes.

The study [135] cited by the commenter to support the notion that 91 to 96 percent of Hg emitted from power plants travels beyond 50 km is based on a photochemical transport model (the TEAM model) that does not employ current state-of-the-science and is not actively developed or updated. Furthermore, the modeling is based on grid cells that are 20 km in size, which limits generalizability to EPA modeling performed at 12 km grid resolution using a state of the science photochemical grid model. The cited modeling study ignores dry deposition of elemental Hg from all sources, an assumption that clearly limits the regional impacts from sources.[136] The methodology of this study cited by the commenter is critically flawed in that it presents no results where individual Hg emission sources are removed and the difference between the zero out simulation (where emissions from U.S. EGUs are set to zero) and the baseline model simulations are directly compared. Finally, the modeling study cited by the commenter presents an illustration of gridded total annual Hg deposition from the TEAM model for the eastern U.S. that clearly shows elevated annual total Hg deposition in the vicinity of coal-fired power plants in the Ohio River Valley and northeast Texas.

d. Hg Risk TSD

1. Assumption of Linear Proportionality in Relationship Between Changes in Hg Deposition and Changes in Fish Tissue Hg Concentrations (Mercury Maps)

Comment: Several commenters criticized EPA's assumption that changes in deposition resulting from U.S. EGU emissions of Hg will result in proportional changes in fish tissue Hg concentrations at the watershed level, as supported by the Mercury Maps modeling exercise. According to one commenter, the Mercury Maps model has limited capability to adequately determine bioaccumulation in fish. The same commenter stated that the Mercury Cycling Model (MCM) developed by EPRI is a more rigorous model that was developed expressly to evaluate the relationship between changes in atmospheric Hg deposition to waterbodies and changes in fish tissue MeHg levels.

Several commenters stated that the Mercury Maps model has many deficiencies. Those commenters stated that Mercury Maps is a static model unable to account for the dynamics of ecosystems that affect Hg bioaccumulation in fish, cannot consider non-air Hg inputs to watersheds, and assumes reductions in airborne Hg lead to proportional reductions in fish MeHg concentrations. Another commenter claimed that data that demonstrate a steady-state linear reduction in fish tissue MeHg in response to a reduction in atmospheric Hg deposition within watersheds do not exist and provided several references that they claimed show non-linear responses to changes in Hg deposition.[137] [138]

The same commenter disagreed with EPA's interpretation of Figure 2–17 in the March TSD and stated that a U.S. Geological Survey national waterway study [139] showed that sheet flow and drainage, not deposition, dominated input to the waterbodies it surveyed. The commenter stated that sheet flow and drainage could contain Hg and thus complicate the relationship that EPA asserts is linear and direct. Another commenter cited Figure 2–17 in the Hg Risk TSD as showing that there is no well-defined relationship between Hg deposition and MeHg concentrations in fish tissue on a national basis.

Several commenters provided comments related to the assumption that fish tissue Hg levels used in the analysis represent a steady-state. One commenter stated that given the demonstrated lag time in response to deposition change, it is logical to conclude that a lag time needs to be incorporated in Mercury Maps to adjust the estimation of how much fish tissue MeHg levels decrease in response to decreases in Hg deposition attributable to U.S. EGUs. According to the same commenter, the METAALICUS study shows that there is a lag time (and a non-proportional response) after 3–4 years. The same commenter noted that there are numerous factors that influence lag time including (1) watershed characteristics,[140] (2) the fact that watersheds may act as legacy sources releasing Hg when disturbed,[141] (3) the magnitude of emission reductions and subsequent changes in atmospheric deposition need to be weighed against the amount of Hg already in an ecosystem,[142] (4) the distance of an ecosystem from Hg sources,[143] and (5) the fact that Hg deposited to aquatic ecosystems becomes less available for uptake by biota over time.[144] Another commenter stated that additional Mercury Maps assumptions do not allow for considerations of lag in response to changes in: (1) Deposition, (2) legacy sources of Hg such as mining, (3) historical Hg deposition, (4) natural Hg levels in fish, (5) ecosystem dynamics over time, or (6) the relative source contributions over time. Another commenter stated that lag times need to be included in the modeling and be able to vary from watershed to watershed and sometimes even from waterbody to waterbody within a watershed. Several commenters stated that the emission rates of Hg due to U.S. sources have been decreasing for more than a decade, while emissions due to sources outside the U.S. have been increasing. For this reason, the commenter asserted that the system is not at steady-state, a basic premise of the model. Another commenter stated that while the time lag for deposition to reach a waterbody is mentioned in the Hg Risk TSD, there is no discussion of the fact that a

[135] Seigneur *et al.*, 2006.

[136] *Id.*

[137] Harris., R.C., John W.M. Rudd, Marc Amyot, Christopher L. Babiarz, Ken G. Beaty, Paul J. Blanchfield, R.A. Bodaly, Brian A. Branfireun, Cynthia C. Gilmour, Jennifer A. Graydon, Andrew Heyes, Holger Hintelmann, James P. Hurley, Carol A. Kelly, David P. Krabbenhoft, Steve E. Lindberg, Robert P. Mason, Michael J. Paterson, Cheryl L. Podemski, Art Robinson, Ken A. Sandilands, George R. Southworth, Vincent L. St. Louis, and Michael T. TateRudd, J. W.M., Amyot M., *et al.*, Whole-Ecosystem study Shows Rapid Fish-Mercury Response to Changes in Mercury Deposition. Proceedings of the National Academy of Sciences Early Edition, PNAS 2007 104 (42) pp. 16586–16591; (published ahead of print September 27, 2007).

[138] Orihel D.M., Paterson M.J., Blanchfield P.J., Bodaly R.A., Gilmour C.C., Hintelmann H., 2007. ''Temporal Changes in the Distribution, Methylation, and Bioaccumulation of Newly Deposited Mercury in an Aquatic Ecosystem,'' *Environmental Pollution*, 154, 77–88.

[139] Scudder B.C., Chasar L.C., Wentz D.A., Bauch N.J., Brigham M.E., Moran P.W., Krabbenhoft D.P., 2009. *Mercury in fish, bed sediment, and water from streams across the United States, 1998–2005:* U.S. Geological Survey Scientific Investigations Report 2009–5109, 74 p.

[140] Grigal D.F., 2002. ''Inputs and Outputs of Mercury from Terrestrial Watersheds: A Review,'' *Environmental Review,* 10, 1–39.

[141] Yang H., Rose N.L., Battarbee R.W., Boyle J.F., 2002. ''Mercury and Lead Budgets for Lochnagar, a Scottish Mountain Lake and Its Catchment,'' *Environmental Science & Technology,* 36, 1383–1388.

[142] Krabbenhoft D.P., Engstrom D., Gilmour C., Harris R., Hurley J., Mason R., 2007. Monitoring and Evaluating Trends in Sediment and Water Indicators. In Harris R., Krabbenhoft D., Mason R., Murray M.W., Reash R., Saltman T. (Eds.), *Ecosystem Responses to Mercury Contamination: Indicators of Change*. New York: Society of Environmental Toxicology and Chemistry (SETAC) North America Workshop on Mercury Monitoring and Assessment, CRC, pp. 47–87.

[143] Lindberg S. *et al.* 2007. ''A synthesis of progress and uncertainties in attributing the sources of mercury in deposition.'' Ambio 36(1): 19–32.

[144] Orihel D.M., Paterson M.J., Blanchfield P.J., Bodaly R.A., Hintelmann H., 2008. ''Experimental Evidence of a Linear Relationship between Inorganic Mercury Loading and Methylmercury Accumulation by Aquatic Biota,'' *Environmental Science & Technology,* 41, 4952–4958.

portion of the deposition is unlikely to reach the water at all.

One commenter believes EPA incorrectly implied that its EGU risk estimates using Mercury Maps are underestimated because they do not account for legacy EGU-attributable deposition, which EPA assumes to be higher.

One commenter stated that while EPA properly screened out watersheds with significant current non-air sources of Hg, the EPA did not adequately screen out watersheds with significant Hg contributions from non-air sources, specifically watersheds with historic Hg or gold mining or other industrial Hg discharges. The same commenter stated that EPA's study was not geographically balanced and was dominated by rivers in the coastal region of the southeast that has numerous wetlands, which are favorable locations for methylation and have conditions that are not typical of much of the rest of the U.S.

Response: The EPA disagrees with the commenters who challenged the assumption of a linear proportional relationship between changes in U.S. EGU deposition and fish tissue Hg levels. The EPA specifically asked the SAB to evaluate EPA's assumption of linear proportionality in the relationship between Hg deposition and fish tissue MeHg concentrations, supported by the Mercury Maps analysis. The SAB peer review committee provided the following overall response, which generally supports EPA's approach:

> The SAB agrees with the Mercury Maps approach used in the analysis and has cited additional work that supports a linear relationship between mercury loading and accumulation in aquatic biota. These studies suggest that mercury deposited directly to aquatic ecosystems can become quickly available to biota and accumulated in fish, and reductions in atmospheric mercury deposition should lead to decreases in methylmercury concentrations in biota. The SAB notes other modeling tools are available to link deposition to fish concentrations, but does not consider them to be superior for this analysis or recommend their use. The integration of Community Multiscale Air Quality Modeling System (CMAQ) deposition modeling to produce estimates of changes in fish tissue concentrations is considered to be sound. Although the SAB is generally satisfied with the presentation of uncertainties and limitations associated with the application of the Mercury Maps approach in qualitative terms, it recommends that the document include quantitative estimates of uncertainty available in the existing literature.[145]

The SAB peer review committee specifically addressed the MCM suggested by the commenter and had the following response:

> The SAB agrees with the application of Mercury Maps in this assessment. There are other modeling tools capable of making a national scale assessment, such as the Regional Mercury Cycling Model (R–MCM). However, the R–MCM is more data intensive and the results produced by the two model approaches should be equivalent.
>
> The R–MCM, a steady-state version of the time-dependent Dynamic Mercury Cycling Model, has been publicly available to and used by the EPA (Region 4, Athens, Environmental Research Laboratory) for a number of years. R–MCM requires more detail on water chemistry, methylation potential, etc., and yields more information as well. Substantial data support the Mercury Maps and the R–MCM steady-state results, so that the results of the sensitivity analysis and the outcomes from using the alternative models would be equivalent between the two modeling approaches. Though running an alternative model framework may provide additional reassurance that the Mercury Maps ''base case'' approach is a valid one, it is unlikely that substantial additional insight would be gained with the alternative model framework.[146]

In addition, the SAB stated, ''Since the Mercury Maps approach was developed, several recent publications have supported the finding of a linear relationship between mercury loading and accumulation in aquatic biota.[147] [148] [149] These studies suggested that mercury deposited directly to aquatic ecosystems can become quickly available to biota and accumulated in fish, and that reductions in atmospheric mercury deposition should lead to decreases in methylmercury concentrations in biota. These results substantiate EPA's assumption that proportionality between air deposition changes and fish tissue methylmercury level changes is sufficiently robust for its application in this risk assessment.'' [150]

Based on the responses of the SAB peer review committee, the EPA's use of the linear proportionality assumption, supported by the Mercury Maps analysis, is well-supported.

The EPA also disagrees with commenters' interpretation of Figure 2–17. As stated in the Hg Risk TSD, while this figure is useful to demonstrate the lack of correlation across watersheds between total deposition of Hg and MeHg concentrations in fish tissue, it is not indicative of the likely correlation between changes in Hg deposition at a given watershed and changes in MeHg concentrations in fish tissue from that watershed. The SAB agreed with this interpretation, noting the importance of Figure 2–17 demonstrating that ''spatial variability of deposition rates is only one major driver of spatial variability of fish methylmercury and that variability of ecosystem factors that control methylation potential (especially wetlands, aqueous organic carbon, pH, and sulfate) also play a key role.'' [151]

In response to recommendations from the SAB, the EPA expanded the discussion of uncertainties associated with the linearity assumption, including uncertainties related to the potential for sampled fish tissue Hg level to reflect previous Hg deposition and the potential for non-air sources of Hg to contribute to sampled fish tissue Hg levels. Each of these sources of uncertainty may result in potential bias in the estimate of exposure associated with current deposition. The EPA took steps to minimize the potential for these biases by (1) only using fish tissue Hg samples from after 1999, and (2) screening out watersheds that either contained active gold mines or had other substantial non-U.S. EGU anthropogenic emissions of Hg. The SAB commented that EPA's approach to minimizing the potential for these biases to affect the results of the risk analysis appears to be sound and that additional criteria that could be applied are unlikely to substantially change the results. As a result, the EPA disagrees with the commenter that EPA's screening process is inadequate. In addition, we conducted several sensitivity analyses to gauge the impact of excluding watersheds with the potential for non-EGU Hg emissions, and found that the results were robust to these exclusions.

In response to specific comments regarding the use of the Mercury Maps model, the EPA clarifies that the Hg Risk TSD did not directly use the Mercury Maps model. Instead, the EPA applied an assumption of linear proportionality between changes in Hg deposition and changes in MeHg concentrations in fish that is supported by the Mercury Maps modeling. By assuming steady-state conditions in apportioning fish tissue Hg levels and risk, the EPA does not attempt to project lag times. Recent research cited by the SAB [152] [153] [154] identifies relatively rapid response of fish tissue Hg to changes in Hg loading, which suggests that fish tissue Hg levels could react more

[145] U.S. EPA–SAB, 2011.

[146] U.S. EPA–SAB, 2011.

[147] Orihel *et al.,* 2007.

[148] Orihel *et al.,* 2008.

[149] Harris *et al.,* 2007.

[150] U.S. EPA–SAB, 2011.

[151] U.S. EPA–SAB, 2011.

[152] Orihel *et al.,* 2007.

[153] Orihel *et al.,* 2008.

[154] Orihel *et al.,* 2007.

quickly to reductions in Hg deposition than previously thought. This finding reduces concern that fish tissue Hg levels could be linked to older patterns of Hg deposition and strengthens the approach used in the revised Hg Risk TSD. While fish tissue may respond rapidly to changes in Hg loading, this does not change the fact that previously emitted Hg from U.S. EGUs can be re-emitted and re-deposited, and thus affect Hg concentration in fish.

2. Characterization of Subsistence Fishing Populations and Exposure Scenario

Comment: Several commenters stated that EPA provides no clear definition of subsistence, near subsistence, or high-end fish consumption, instead assuming that poverty is a direct indication of subsistence fishing and high-end fish consumption. One commenter stated no documentation exists to supports these assumptions. Another commenter stated that EPA's definitions of subsistence fishers in the Hg Risk TSD are not consistent with earlier EPA documents and are used inconsistently throughout the Hg Risk TSD. Several commenters stated that while subsistence fishing can be associated with poverty, poverty does not indicate subsistence fishing. One commenter stated that by including watersheds with as few as 25 members of individuals living in poverty, the EPA overstates risks.

One commenter stated that it is unclear what literature the Agency says ''generally supports the plausibility of high-end subsistence-like fishing * * * to some extent across the watersheds'' and stated that if other studies exist, the EPA should provide the values for comparison.

One commenter stated that EPA combined two parameters with differing scales to establish the geographic unit used in the Hg Risk TSD risk assessment. The HUC watersheds are based on average about 35 square miles in size, while U.S. census tracts used to identify watersheds relevant for subpopulations of interest—cover a few tenths to hundreds of square miles. Several commenters stated that it is unclear how the analysis handled differences in geographic resolution between watersheds and census tracts were.

One commenter stated that the procedure for assigning census tracts could bias exposure outcomes. For example, the commenter stated that a single influential census tract in a watershed could drive risk, even if the watershed had only a minimal number of fish samples. The commenter stated that this possibility is a concern in urban areas, which account for the majority of census tracts, because these census tracts are more likely to be included in a risk analysis because they have more than 25 people living in poverty. The commenter stated that these census tracts may drive the extremes of the distribution without regard to the actual number of high-level, self-caught fish consumers within their boundaries. The commenter stated that they could not assess the potential bias and noted that EPA did not test the bias by sensitivity analyses.

Several commenters stated that EPA was not clear whether the poverty criteria were applied in all scenarios or just for the high-end female fish consumer scenario. One commenter stated that EPA should apply the minimum 25 source population criteria only to populations of women of childbearing age. One commenter stated that EPA's assumption would result in any densely populated urban census tract with a single fish tissue sample being assigned to a modeled watershed with populations potentially at-risk, regardless of the actual degree of recreational or subsistence fishing taking place there.

Response: The EPA agrees with the comments that subsistence fish consumption was not clearly defined, and we have provided a clearer definition in the revised Hg Risk TSD, however, this clarification does not result in any changes to the quantitative analysis. In the revised Hg Risk TSD, the EPA clarifies that ''subsistence fishers'' are defined as individuals who rely on noncommercial fish as a major source of protein.[155] This definition is reflected in the range of fish consumption rates used in estimating risk. The likely presence of this type of subsistence fish consumer is supported by available peer reviewed literature (*see* Table 1–5 of the revised Hg Risk TSD). These studies clearly show that a subset of surveyed fishers consumes self-caught fish at the rates cited in the Hg Risk TSD. The SAB peer review concluded that the consumption rates and locations for fishing activity are supported by the data presented in the Hg Risk TSD, and are generally reasonable and appropriate given the available data.[156]

The EPA notes that there is some confusion in the comments related to the size of the watersheds modeled. Several commenters stated that HUC watersheds are 35 km on a side. The commenters appear to be referring to HUC8 classifications. The HUCs are defined for varying spatial resolutions. The geographic unit used as the basis for generating risk estimates is HUC12, which are watersheds about 10 km on a side, which is comparable with the size of the 12 km^2 grid cells in CMAQ, which are 12 km^2. The EPA has also clarified that the specific unit of analysis for this assessment is at the watershed, not enumerated subpopulations.

The EPA only used the U.S. Census tracts to determine whether there are populations in the vicinity of a given watershed, which could increase the potential for a category of subsistence fishers to be active at that watershed. In the revised Hg Risk TSD, the EPA modified the female subsistence scenario to apply equally to all watersheds with fish tissue Hg data based on the likelihood that these populations have the potential to fish at most watersheds. As described in the revised Hg Risk TSD, the EPA made this change in response to SAB's concerns regarding the potential exclusion of watersheds with fewer than 25 individuals and regarding coverage for high-end recreational fish consumption.[157] Thus, concerns regarding the use of census data to select watersheds with the potential for subsistence fishing no longer apply to this scenario. However, for the remaining subsistence scenarios, the EPA continues to use U.S. Census tract-level data to evaluate the presence of a ''source population'' in the vicinity of the watershed being modeled for risk. In this context, the EPA uses the U.S. Census data to assess whether a socioeconomic status (SES)-differentiated group similar to the particular type of subsistence fisher being modeled (*e.g.,* poor Hispanics) are located in the vicinity of the watershed. If a source population is nearby, then this increases the potential that subsistence fishing activity could occur for that population scenario.

The EPA continues to model risk for white and black subsistence fishers active in the southeast and for Hispanics assessed nationally. In this case, the EPA links poverty with subsistence fishing, as EPA only modeled locations with poor source populations. However, in modeling these three populations, the

[155] U.S. EPA, U.S. Environmental Protection Agency. 2000. *Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories,* Volume 3: Overview of Risk Management. Office of Science and Technology, Office of Water, U.S. Environmental Protection Agency, Washington, DC EPA 823–B–00–007.

[156] U.S. EPA–SAB, 2011.

[157] This change led to a very small increase in the number of watersheds with populations potentially at-risk. In the Hg Risk TSD accompanying the proposed rule, approximately 4 percent of modeled watersheds were excluded based on the SES-based filtering criteria.

EPA asserts that the presence of a poor source population indicates the potential for subsistence fishing activity, rather the presence of such activity. The linkage between poverty and higher rates of subsistence fish consumption is supported by the Burger *et al.* study,[158] which identified substantially higher consumption rates for poor individuals (*see* Table 5 of the study). The EPA acknowledges that subsistence fishing activity by specific subpopulations might only be present across a subset of the watersheds EPA modeled for risk. However, given the stated goal of the analysis to determine the percent of watersheds where the potential exists for exposures to U.S. EGU-attributable Hg to represent a public health hazard, identifying a set of watersheds with the potential for the type of high fish consumption that leads to high Hg exposure is appropriate. The EPA notes that relatively few watersheds (less than 4 percent) have fish tissue Hg data, and, thus, can be included in the risk assessment. Consequently, while there is the potential for including some watersheds in the analysis that may not have currently active subsistence fishing activity, it is likely that EPA excluded other watersheds from the analysis where this type of subsistence fishing activity occurs due to a lack of fish tissue Hg data.

While EPA agrees with the comment that it is likely that exposure to total MeHg through commercial fish consumption represents a more significant risk for the general population than consumption of freshwater fish obtained through self-caught fishing activity, exposure to total MeHg through self-caught fish consumption is the most significant risk for subsistence fishing populations and high-end recreational fishers. For the subset of these populations that focus their fishing activity in freshwater streams and lakes, it is also the case that they will experience a higher fraction of MeHg exposure attributable to U.S. EGU Hg emissions. As a result, the EPA focused the risk assessment on subsistence fishers active at inland freshwater watersheds because they are likely to experience the highest levels of individual risk as a result of exposure to U.S. EGU-attributable Hg.

3. Cooking Loss Adjustment Factor

Comment: Several commenters stated that EPA did not justify the selection of a cooking loss factor of 1.5 that, according to one commenter, increases estimated intake by 50 percent, thus increasing the daily MeHg intake rate by a constant factor of 33 percent and also increasing any resulting (HQ) risk estimate by a similar factor. Several commenters stated that the source of EPA's selected loss factor [159] reported a range of cooking losses from 1.1 to 6. Several commenters cite several studies that report no or highly variable changes in MeHg levels as a result of cooking fish.[160] [161] [162] [163] [164] One commenter suggested that EPA's cooking loss adjustment factor of 1.5 is at the high-end of the values supported by the literature. Another commenter stated that EPA has used other adjustment factors in previous documents, and that the adjustment factor should not be fixed across different populations given potential differences in cooking practices. Several commenters noted that the cooking loss adjustment factor should only be applied to estimates of consumption rates for prepared fish, and that some sources of consumption rates are based on raw fish.

Response: The EPA disagrees with the commenters that the selection of the cooking loss factor of 1.5 is not justified by the literature. The EPA also disagrees with the comment that the cooking loss adjustment factor of 1.5 is at the high-end of the range of values in the literature. The EPA selected the Morgan study [165] as the basis for the food preparation/cooking adjustment factor because it focused on the types of freshwater fish species representative of what might be consumed by subsistence fishing populations (*i.e.,* walleye and lake trout). This study [166] provides a range of adjustment factors for each fish type including 1.1 to 1.5 for walleye and 1.5 to 2.0 for lake trout. Given these two ranges, the EPA determined it to be reasonable to take an intermediate value between the two ranges (*i.e.,* 1.5), rather than focus on either the highest or lowest values, which is not the most conservative assumption that the EPA could have made. This study [167] also explains that preparation/cooking of fish results in an increase in MeHg levels per unit fish because Hg concentrates in the muscle, while preparation/cooking tends to reduce non-muscle elements (*e.g.,* water, bone, fat).

Regarding the alternative studies identified by the commenters, the EPA disagrees that these studies considered collectively contradict the cooking loss factor in the analysis. Specifically, the first study [168] may have included measurement of non-fish components added to dishes (*e.g.,* onions, heavy breading etc.), which could dilute the post-cooking Hg measurements and give the appearance of a cooking loss even as actual fish tissue Hg levels could have increased. In the second study,[169] the fish species are saltwater and not freshwater, and the authors note that the reduction of water and fat could increase in the Hg concentration without changing absolute content. The third study focused on measurement of *bioaccessible Hg* in raw and cooked fish.[170] However, available information currently allows us to specify the risk model in terms of total Hg intake, not bioaccessible Hg, thus, this article is potentially informative for guiding future research and methods development, not the current risk assessment. The fourth study [171] found a modest but statistically insignificant increase in Hg levels for most of the cooking methods assessed, which is directionally consistent with EPA's cooking loss adjustment. The fifth study [172] only addressed the issue qualitatively, thus cannot be used for the cooking loss factor. When considered collectively, the EPA disagrees that the additional studies identified by the commenter contradict the cooking loss factor used in the risk assessment and maintains that the Morgan study [173] remains the most

[158] Burger, J., 2002. ''Daily Consumption of Wild Fish and Game: Exposures of High End Recreationists,'' *International Journal of Environmental Research and Public Health,* 12 (4), 343–54.

[159] Morgan, J.N., M.R. Berry, and R.L. Graves. 1997. ''Effects of Commonly Used Cooking Practices on Total Mercury Concentration in Fish and Their Impact on Exposure Assessments.'' *Journal of Exposure Analysis and Environmental Epidemiology* 7(1):119–133.

[160] Armbruster G., Gerow K.G., Lisk D.J., 1988. ''The Effects of Six Methods of Cooking on Residues of Mercury in Striped Bass,'' *Nutrition Reports International,* 37, 123–126.

[161] Gutenmann, W.H. and Lisk D.J., 1991. ''Higher Average Mercury Concentration in Fish Fillets after Skinning and Fat Removal,'' *Journal of Food Safety,* 11, 99–103.

[162] Farias L.A., Favaro, D.I., Santos J.O., Vasconcellos M.B., *et al.,* 2010. ''Cooking Process Evaluation on Mercury Content in Fish,'' *Acta Amazonia,* 40 (4), 741–748.

[163] Perelló G., Martí-Cid R., Llobet J.M., Domingo J.L., 2008. ''Effects of Various Cooking Processes on the Concentrations of Arsenic, Cadmium, Mercury, and Lead in Foods,'' *Journal of Agricultural and Food Chemistry,* 156 (22), 11262–11269.

[164] Torres-Escribano S., Ruiz A., Barrios L., Vélez D., Montoro R., 2011. ''Influence of Mercury Bioaccessibility on Exposure Assessment Associated with Consumption of Cooked Predatory Fish in Spain,'' *Journal of the Science of Food and Agriculture,* 91 (6), 981–6.

[165] Morgan *et al.,* 1997.

[166] *Id.*

[167] *Id.*

[168] Farias *et al.,* 2002.

[169] Perelló *et al.,* 2008.

[170] Torres-Escribano *et al.,* 2011.

[171] Armbruster *et al.,* 1988.

[172] Gutenmann *et al.,* 1991.

[173] Morgan *et al.,* 1997.

applicable for characterizing cooking/preparation effects on Hg concentrations in fish.

The EPA agrees that application of the cooking loss adjustment factor is appropriate if the fish consumption rates are for *as cooked* or *as consumed* and not for raw fish. Careful review of the three studies used in the risk assessment to identify subsistence fisher consumption rates suggests that all three represent annual-average daily intakes (g/day) of *as consumed* or *as cooked* fish. One study stated that they used models of portion or meal size servings (the size of the serving the respondent regularly eats).[174] Therefore, the EPA interprets the fish consumption rates provided in this study [175] as representing *as cooked/prepared* and not for raw fish and for that reason, application of a preparation/cooking adjustment factor is required. Another study [176] used different sized models of cooked fish filets and therefore these consumption rates are also interpreted as represented *as cooked/prepared* and not raw fish. One study [177] [178] queried survey responders for meal portion or serving size and therefore, the consumption rates do represent *as cooked/prepared.* Because all three studies provide consumption rates based on *as cooked/prepared* or as consumed, it is appropriate to apply the cooking loss adjustment factor in modeling exposure.

4. Fish Consumption Rates and Fish Tissue Hg Characterization

Comment: One commenter stated that in the past the Agency has recommended various default consumption rates (in the general range of 130 to <150 g/day) to provide default intakes for subsistence fishers under the *Risk Assessment Guidance for Superfund (RAGS) or the Fish Advisory Guidance.*[179] [180] The commenter stated that these default consumption rates are derived from various studies and generally are based on 90th or 99th percentile distribution estimates. Another commenter stated that EPA's use of the 99th percentile fish consumption for its risk analysis is inconsistent with the Agency's risk assessment guidelines, which recommend evaluating a reasonable maximum exposure (''RME'') scenario,[181] which equates to about a 95th percentile fish consumption value. The same commenter stated that EPA applied the 99th percentile to a ''small survey of 149 South Carolina female anglers'' to calculate an ingestion rate of 373 grams per day (g/day). The commenter stated that if the 95th percentile is used the ingestion rate would be 173 g/day and if the default ingestion rate for determining ambient water standards is used the ingestion rate would be 142 g/day.

Several commenters stated that EPA based its fish consumption rates used in the risk analysis on a limited number of studies and that those studies are poorly documented.

Another commenter stated that EPA should summarize available supporting studies by basic study content, characteristics, design, size, demographics, dietary recall period, and fish intake rates by demographic variables. According to the commenter, this summary would support the scientific validity of the assessment and better illustrate the potential variability and uncertainty involved in extrapolating data from small populations to the national-scale. The commenter also noted that the three studies actually used to provide subsistence population estimates, which were extrapolated to the national-scale, included a limited number of individuals living in diverse and localized areas.

One commenter stated that the assumption with the greatest impact on risk is the fish consumption rate. That same commenter stated that using 99th percentile ingestion rate dramatically increases HQ and IQ loss compared to the 50th percentile ingestion rate. The commenter stated that when an estimate of the 95th percentile ingestion rate of the 15 to 44 year old female population is considered, the HQ is a tenth of the value computed with the 99th percentile high-end female fisher.

One commenter stated that EPA provides broad summary statistics of its fish tissue data in Table 5–2 of the Regulatory Impact Analysis (RIA), but the summary does not allow an assessment of the representativeness and robustness of the underlying data for the risk assessment, especially at the tails of the distribution. The commenter stated that the table does not include a median statistic and does not provide any information on the number of lakes and river segments in each watershed. According to the commenter, an analysis of EPA's database by the SAB indicated that 60 percent of the watersheds with fish Hg data from rivers have risks calculated based upon a sample size of one or two fish. The commenter stated that it is not reasonable to base a significant policy and regulation decision on watersheds where exposure is based on a single fish sample in a single water body within it.

Several commenters criticized EPA's use of the 75th percentile fish tissue MeHg level in a watershed. One commenter stated that EPA provided no rationale for its decision to choose the highest of the 75th percentile for fish Hg levels among rivers and lakes within the HUC. Several commenters stated that subsistence fishers are less likely to target larger fish relative to recreational fishers. Several commenters suggested that EPA include a sensitivity analysis using the mean or median fish MeHg level in a watershed. One commenter also stated that EPA arbitrarily inflated the risk estimates by assuming consumption of only fish greater than 7 inches and choosing the largest of the 75th percentile of fish Hg levels from these larger fish (*i.e.,* larger than 7 inches) for rivers and lakes. That same commenter suggested using the median of all size fish, not just those over 7 inches.

One commenter stated that EPA should quantify adverse effects from the ingestion of MeHg in seafood in addition to ingestion of MeHg from self-caught freshwater fish. According to the commenter, recent studies demonstrate that were EPA to take into account consumption of seafood, MeHg consumption in the U.S. is of even greater concern.

Response: The EPA acknowledges that the focus of the Hg Risk TSD is characterizing risk for the groups likely to experience the greatest U.S. EGU-attributable Hg risk, which are subsistence fishing populations active at inland freshwater lakes and rivers. Specifically, within that subsistence fishing population, the EPA is interested in those individuals who are most at-risk, which includes those who consume the most fish. For that reason, the EPA considered a range of high-end fish consumption rates including the 99th percentile representing the most highly-exposed individuals. In responding to the SAB peer review, the EPA clarified this focus in the

[174] Burger *et al.,* 2002.

[175] *Id.*

[176] Shilling, Fraser, Aubrey White, Lucas Lippert, Mark Lubell (2010). Contaminated fish consumption in California's Central Valley Delta. Environmental Research 110, p. 334–344.

[177] Dellinger JA. 2004. ''Exposure assessment and initial intervention regarding fish consumption of tribal members of the Upper Great Lakes Region in the United States.'' *Environ Res* 95:325–340.

[178] Personal communication, Dr. Dellinger, September 27, 2011.

[179] U.S. EPA. 1991. *Risk Assessment Guidance for Superfund (RAGS).* Part C 1991 EPA/9285.7–01C. October.

[180] U.S. EPA. 2000. *National Guidance: Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories,* Volume 2. EPA 823–B–00–008, November.

[181] U.S. EPA. 1989. *Risk Assessment Guidance for Superfund (RAGS).* EPA/540/1–89/002. December.

introduction to the revised Hg Risk TSD and changed the full title to *revised Technical Support Document: National-Scale Assessment of Mercury Risk to Populations with High Consumption of Self-caught Freshwater Fish.*

The EPA agrees that the fish consumption rate is an important factor in calculating risk from exposure to MeHg in fish. The EPA acknowledges that the distribution of fish consumption rates is positively skewed, which means that at higher percentiles (*e.g.,* 90th, 95th, and 99th) there is a substantial increase in ingestion rates relative to the mean or median. The revised Hg Risk TSD includes a reasonableness check on the amount of fish consumed (as a daily value) reflected in the different rates. While the 99th percentile consumption rates for the subsistence female fisher (373 g/day) is substantially higher than the 90th or 95th percentile values (123 and 173 g/day respectively), the 99th percentile value translates into a 13-ounce meal. While this represents a large serving, it is still reasonable if representing an individual who receives all of their meat protein from self-caught fishing, and the 13 ounces per day do not have to be eaten all at one meal. The higher consumption rates (i.e., greater than 250 g/day) are supported by all three studies used in the risk assessment, and therefore, there is support across studies near the upper bound of likely consumption rates in this range. The EPA acknowledges uncertainty associated with estimating high-end percentile values in these studies due to relatively low sample sizes for some population groups. However, even if a few individuals reported these high self-caught fish consumption rates, making it difficult to characterize the population percentiles they represent, the values still suggest that these levels of high fish consumption exist among surveyed individuals. To determine whether a public health hazard could exist, the EPA asserts that it is reasonable to include these consumption rates as representative of the most at-risk populations. In these cases, however, the EPA acknowledges that it is important to highlight uncertainty associated with characterizing the specific population percentile that these ingestion rates represent, and EPA has done so in the revised Hg Risk TSD.

The EPA disagrees with the comment that high consumption rates are poorly documented. Evidence of these high fish consuming populations can be found in surveys [182] and specialized studies.[183] [184] [185] [186] [187] Several studies identified additional fishing populations with subsistence or near subsistence consumption rates, including urban fishing populations (including low-income populations),[188] [189] [190] Laotian communities,[191] and Hispanics. The EPA participated in 1999 in a project investigating exposures of poor, minority communities in New York City to a number of contaminants including Hg, which found these populations can have very high fish consumption rates.[192] The SAB concluded that the consumption rates and locations for fishing activity are supported by the data presented in the Hg Risk TSD, and are generally reasonable and appropriate given the available data.[193]

The EPA agrees that the Hg Risk TSD would be improved by clarifying that the literature review focused on identifying studies that characterize subsistence fish consumption for groups active at freshwater locations within the U.S., and EPA has revised the Hg Risk TSD accordingly. In the Hg Risk TSD, the EPA summarized important study attributes for the source studies used to obtain fish consumption rates. This information was provided in Table C–1 in an appendix. To improve clarity, the EPA moved the summary table to the main body in the revised Hg Risk TSD. In identifying these studies, the EPA focused on surveys for subsistence fishers that were applicable at the broader regional or national level. In the Hg Risk TSD, the EPA acknowledged the smaller sample sizes for some of the subsistence fisher groups, and in several cases the EPA did not use the 99th percentile consumption rates because the sample sizes were too low to support this level of resolution. This decision did not affect EPA's finding of a hazard to public health, which is based on the results for the female subsistence fishing population, which has an estimate of the 99th percentile consumption rate that is supported by an adequate sample size.

The EPA disagrees with the comment that it did not provide a rationale for choosing the 75th percentile fish tissue concentration across lakes and rivers in a watershed. However, the EPA modified the methodology based on evaluation of the number of samples within each watershed (responding to a recommendation from the SAB). In the revised methodology, the EPA computes the 75th percentile value at each sampling site within a watershed. The EPA then computed the average of the site-specific 75th percentile fish tissue Hg values within a given watershed. This approach does not differentiate between rivers and lakes and reflects an improved treatment of behavior, allowing for fishers to choose among multiple fishing sites within a watershed.

The EPA generally agrees with the comment that some fraction of subsistence fishers likely consume fish without consideration for size (given dietary necessity), however, the EPA considers it reasonable to assume that a subset of subsistence fishers could target larger fish in order to maximize the potential consumption per unit of fishing effort. The EPA uses this subset of subsistence fishers targeting larger fish, which is represented by the 75th percentile fish tissue value, in the risk assessment. In addition, including the female subsistence fishing population in the analysis also provides coverage for high-end recreational anglers who target larger freshwater fish. The SAB commented that: ''Using the 75th percentile of fish tissue values as a reflection of consumption of larger, but not the largest, fish among sport and subsistence fishers is a reasonable approach and is consistent with published and unpublished data on predominant types of fish consumed.'' [194] The SAB suggested that EPA include a sensitivity analysis based on use of the median value, and EPA has done so in the revised Hg Risk TSD. This sensitivity analysis showed that using the median estimates had only a small impact on the number and percent of modeled watersheds with

[182] Burger *et al.,* 2002.

[183] Burger, J., K. Pflugh, L. Lurig, L. Von Hagen, and S. Von Hagen. 1999a. ''Fishing in Urban New Jersey: Ethnicity Affects Information Sources, Perception, and Compliance.'' *Risk Analysis* 19(2): 217–229.

[184] Burger, J., Stephens, W. L., Boring, C. S., Kuklinski, M., Gibbons, J. W., Gochfeld M. 1999b. ''Factors in Exposure Assessment: Ethnic and Socioeconomic Differences in Fishing and Soncumption of Fish Caught along the Savannah River.'' *Risk Analysis,* Vol. 19, No. 3, p. 427.

[185] California Environmental Protection Agency (CalEPA). 1997. *Chemicals in Fish Report No. 1: Consumption of Fish and Shellfish in California and the United States Final Draft Report.* Pesticide and Environmental Toxicology Section, Office of Environmental Health Hazard Assessment, July.

[186] Tai, S. 1999. ''Environmental Hazards and the Richmond Laotian American Community: A Case Study in Environmental Justice.'' Asian Law Journal 6: 189.

[187] Corburn, J. 2002. ''Combining community-based research and local knowledge to confront asthma and subsistence-fishing hazards in Greenpoint/Williamsburg, Brooklyn, New York.'' *Environmental Health Perspectives* 110(2).

[188] Burger *et al.,* 1999a.

[189] Burger *et al.,* 1999b.

[190] CalEPA, 1997.

[191] Tai, 1999.

[192] Corburn, 2002.

[193] U.S. EPA–SAB, 2011.

[194] U.S. EPA–SAB, 2011.

populations potentially at-risk from U.S. EGU-attributable MeHg exposures. In the revised Hg Risk TSD, the EPA clarified that the 7-inch cutoff represents a minimum size limit for a number of key edible freshwater fish species established at the State-level. For example, Pennsylvania establishes 7 inches as the minimum size limit for both trout and salmon (other edible fish species such as bass, walleye and northern pike have higher minimum size limits).[195]

The EPA disagrees with the comment that it is not reasonable to use watersheds where only a single fish sample is available. Although it is generally preferred to have multiple samples, the SAB noted that using a single sample is likely to underestimate the 75th percentile fish MeHg concentration and is, therefore, likely to underestimate the risk estimates for those watersheds. The SAB suggested that EPA conduct additional analyses of the fish tissue MeHg data, which EPA has done and included in the revised Hg Risk TSD. The revised Hg Risk TSD includes information on the number of watersheds modeled in the risk assessment with various fish tissue Hg samples sizes (e.g., 1, 2, 3–5, 6–10 and >10 measurements).

5. Reference Dose (RfD) for MeHg and Hg Health Effects Studies

Comment: Several commenters stated that EPA's RfD[196] is based on sound science, which was supported by the findings of the NAS Study,[197] and that EPA appropriately applied the RfD in the Hg risk assessment. The commenters also stated that recent studies find clear associations between maternal blood Hg levels and delayed child development and cardiovascular effects, as well as potential for effects due to exposure to pollutant mixtures including lead.

However, many commenters expressed concerns regarding EPA's use of the MeHg RfD as a benchmark for health risk. Several commenters raised concerns claiming that EPA has not incorporated the best available Hg toxicological data into the RfD, which results in a flawed analysis and an overestimate of the impact of Hg emissions on human health.

Several commenters stated that, when deriving the RfD, the EPA relied on the flawed Faroe Islands' children study and ignored the Seychelles Islands study,[198] which did not confirm any harm on children due to MeHg exposure. According to the commenters, application of the Faroe Island study is suspect because (1) the raw data from the study have never been made available for independent analysis and scrutiny, (2) there is potential for confounding by polychlorinated biphenyls (PCBs) and lead, (3) population exposure to MeHg was through consumption of highly contaminated pilot whale meats and blubbers, and (4) exposure levels in the U.S. remain lower than those observed in the primary study. One commenter also notes that (1) Seychelles Islanders consume far more fish than Americans do; (2) the amount of MeHg in the U.S. population is much lower than the Seychelles Islanders; and (3) all ocean fish contain about the same amount of MeHg, so MeHg intake per fish meal is similar between Americans and Seychelles Islanders. However, another commenter stated that industry arguments against using the Faroe Islands study fail to acknowledge that the study results were consistent with studies in the Seychelles Islands, New Zealand,[199] and Poland.[200]

One commenter criticized EPA for using a linear dose-response model for the RfD-based HQ metric and the IQ metric. Another commenter stated that the RfD assumes a threshold dose below which an appreciable risk of adverse effects is unlikely, and NAS did not evaluate whether MeHg exposure data were better fit by a linear or non-linear model or by a threshold or non-threshold model.

Several commenters stated that EPA's MeHg RfD is more conservative than ''safe'' levels determined by other federal agencies and claim that EPA assigned unusually high uncertainty factors. Several commenters stated that EPA's use of the 1999 National Health and Nutrition Examination Survey (NHANES) blood Hg levels show a downward trend since 1999, and the levels have been below the RfD since 2001.

One commenter stated that a study by Texas Department of State Health Services (DSHS, 2004)[201] determined that among subsistence fishers who eat fish from Caddo Lake with elevated MeHg, women of child-bearing years did not have blood Hg levels greater than the RfD. Thus, according to the commenter, the connection between MeHg in fish and adverse health effects in the U.S. is not fully understood and could involve other factors, including the protective effects of fatty acids and selenium in fish, which EPA did not taken into account.

Two commenters claim that EPA uses the RfD as if it were an absolute threshold for health risk in the risk assessment even though the RfD methodology is a screening tool for deciding when risks clearly do not exist.

Several commenters recommended adding qualitative discussions to the Hg Risk TSD regarding several aspects of uncertainty, including uncertainty in the RfD, uncertainty in extrapolating a dose-response relationship between MeHg exposure and change in IQ, uncertainty in extrapolating the dose-response relationship from marine fish and marine mammals to freshwater fish, and uncertainty due to potential confounding by PCBs in marine species.

Several commenters raised concerns regarding the relationship between MeHg exposure and IQ loss. Two commenters stated that changes in IQ are not a well-defined health consequence of MeHg exposure. One commenter stated that the SAB had reservations about EPA's use of IQ loss. Two commenters questioned whether IQ impacts would even occur because in Japan and Korea, where the maternal blood Hg levels are higher than in the U.S., there is no evidence of adverse effects. Another commenter cited a study[202] that found verbal IQ scores for children from mothers with no seafood intake were 50 percent more likely to be in the lowest quartile. One commenter questions using an IQ risk metric threshold of >1 or >2 points because variation in IQ measures and the intra-individual variation in IQ are higher than the threshold.

Several commenters question the relationship between cardiovascular effects and MeHg exposure. Two

[195] Pennsylvania Fish and Boat Commission. 2011. *Summary Book: 2011 Pennsylvania Fishing Laws & Regulations* available at: *http://fishandboat.com/fishpub/summary/inland.html.*

[196] U.S. Environmental Protection Agency—Integrated Risk Information System (U.S. EPA–IRIS). 2001. Methylmercury (MeHg) (CASRN 22967–92–6). Available at *http://www.epa.gov/iris/subst/0073.htm.*

[197] NAS, 2000.

[198] Budtz-Jorgensen E, Debes F, Weihe P, Grandjean P. 2005. ''Adverse Mercury Effects in 7–Year-Old Children Expressed as Loss in ''IQ''.'' EPA–HQ–OAR–2002–0056–6046.

[199] Kjellstrom, T; Kennedy, P; Wallis, S; *et al.* 1986. *Physical and mental development of children with prenatal exposure to mercury from fish. Stage 1: Preliminary test at age 4.* Natl Swed Environ Protec Bd, Rpt 3080 (Solna, Sweden).

[200] Wieslaw Jedrychowski *et al.* 2006. ''Effects of Prenatal Exposure to Mercury on Cognitive and Psychomotor Function in One-Year-Old Infants: Epidemiologic Cohort Study in Poland,'' 16 Annals of Epidemiology 439.

[201] DSHS. 2005. *Health Consultation: Mercury Exposure Investigation Caddo Lake Area-Harrison County Texas.* Agency for Toxic Substances and Disease Registry. *http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/sfr/085.pdf.*

[202] Hibbeln JR, Davis JM, Steer C, Emmett P, Rogers I, Williams C, *et al.,* 2007. ''Maternal seafood consumption in pregnancy and neurodevelopmental outcomes in childhood (ALSPAC study): an observational cohort study. '' Lancet 369:

commenters cited studies examining the relationship between MeHg exposure and cardiovascular effects,[203 204 205 206 207 208] but concluded that it seems premature to use these studies to establish a dose-response relationship.

Several commenters assert that the risks from eating seafood are low relative to the benefits, that fish advisories can limit the beneficial aspects of fish consumption, and that fish advisories are often unsuccessful in changing behavior.[209 210] One commenter noted the important protective role of dietary selenium against MeHg toxicity because the binding affinity of Hg to Se is much higher than binding to sulfur.

Response: The EPA agrees with commenters that state the MeHg RfD is the appropriate health value for determining elevated risks from MeHg exposure and disagrees with commenters that state otherwise. At this time, the EPA is neither reviewing nor revising its 2001 RfD for MeHg. The 2001 RfD for MeHg is EPA's current peer-reviewed RfD, which is the value EPA uses in all its risk assessments. The EPA's RfD is based on multiple benchmark doses, and RfDs were calculated on various endpoints using the three extant large studies of childhood effects of in utero exposure: Faroe Islands, New Zealand, and an integrative measure including data from Seychelles. The EPA did not choose to base the MeHg RfD solely on results from the Seychelles Islands, as both the NAS[211] and an independent scientific review panel convened as part of the IRIS process[212] advised strongly against using results from a study that at the time had not shown an association between MeHg exposure and adverse effects. Further, the EPA disagrees with comments stating that EPA based the MeHg RfD solely on results from the Faroe Islands population and disagrees that the information underlying the RfD is ''poorly explained''. The EPA has provided detailed documentation for the choices underlying calculation of the RfD.[213 214 215] To correct a misunderstanding by the commenter, the data underlying the Faroe Islands study have been previously published in the peer reviewed literature.

The EPA disagrees that it did not incorporate the latest Hg data to support the appropriate and necessary finding. It is the policy of EPA to use the most current peer reviewed, publicly available data and methodologies in its risk assessments. However, the EPA noted in the preamble to the proposed rule that ''data published since 2001 are generally consistent with those of the earlier studies that were the basis of the RfD, demonstrating persistent effects in the Faroe Island cohort, and in some cases associations of effects with lower MeHg exposure concentrations than in the Faroe Islands. These new studies provide additional confidence that exposures above the RfD are contributing to risk of adverse effects, and that reductions in exposures above the RfD can lead to incremental reductions in risk.'' However, the EPA has not completed a comprehensive review of the new literature, and as such, it would be premature to draw conclusions about the overall implications for the RfD.

The EPA agrees that EPA's RfD is not the same as the levels used by other federal agencies. In their advice to the EPA on the appropriate bases for a MeHg RfD, NAS specifically recommended that EPA use neither the study nor the uncertainty factor employed by the Agency for Toxic Substances Disease Registry (ATSDR) in the calculation of the minimal risk level.[216]

The EPA disagrees that the uncertainty factor is ''unusually high''. The uncertainty factor used in calculation of EPA's peer-reviewed RfD is small (10 fold); half of this factor is to account for measured variability in human pharmacokinetics, which is based on advice of the NAS[217] and an independent panel of scientific peer reviewers convened as part of the IRIS process.[218]

The IRIS makes this statement regarding a threshold for MeHg, ''It is also important to note that no evidence of a threshold arose for methylmercury-related neurotoxicity within the range of exposures in the Faroe Islands study. This lack [of a threshold] is indicated by the fact that, of the K power models, K = 1 provided a better fit for the endpoint models than did higher values of K.''[219]

The EPA disagrees that it is using the MeHg RfD as an absolute bright line for health effects in the risk assessment. As stated in the preamble to this proposed rule, the RfD is an estimate of a daily exposure to the human population that is likely to be without an appreciable risk of deleterious effects during a lifetime. The EPA also stated that no RfD defines an exposure level corresponding to zero risk. Because mercury is a cumulative neurotoxin, it is important to distinguish health effects from public health hazard. Within the context of the appropriate and necessary finding, we interpret a public health hazard as risk, rather than certain occurrence of health effects.

The EPA disagrees that exposure levels in the U.S. are lower than those in the Faroe Islands study. Exposure to MeHg in the U.S. has been reported at the same levels as those published in the Faroe Islands.[220] One study notes that in the NHANES data (1999 to 2004), the highest five percent of women's blood Hg exceeded 8.2 microgram per liter (μg/L) in the Northeast U.S. and 7.2 μg/L in coastal areas.[221] Higher levels have been reported among subjects known to consume fish. For example, one study reported mean blood Hg for adult women to be 15 μg/L; range for

[203] Roman HA, Walsh TL, Coull BA, Dewailly É, Guallar E, Hattis D, *et al.,* 2011. Evaluation of the Cardiovascular Effects of Methylmercury Exposures: Current Evidence Supports Development of a Dose–Response Function for Regulatory Benefits Analysis. Environ Health Perspect 119:607–614.

[204] Guallar E, Sanz-Gallardo MI, van't Veer P, *et al.,* 2002. ''Mercury, fish oils, and the risk of myocardial infarction.'' N Engl J Med.;347:1747.

[205] Virtanen JK, Voutilainen S, Rissanen TH, *et al.,* 2005. ''Mercury, fish oils, and risk of acute coronary events and cardiovascular disease, coronary heart disease, and all-cause mortality in men in eastern Finland.'' Arterioscler Thromb Vasc Biol. 2005;25:228.

[206] Yoshizawa, Rimm, Morris, Spate, Hsieh, Spiegelman, Stampfer, Willett. ''Mercury and the Risk of Coronary Heart Disease in Men,'' N Engl J Med 2002; 347:1755–1760.

[207] Hallgren CG, Hallmans G, Jansson JH, *et al.,* 2001. Markers of high fish intake are associated with decreased risk of a first myocardial infarction. Br J Nutr: 86:397.

[208] Mozaffarian, Dariush. 2011. ''Mercury Exposure and Risk of Cardiovascular Disease in Two U.S. Cohorts,'' N Engl J Med 364: 1116–1125.

[209] Hibbeln *et al.,* 2007.

[210] Mozaffarian, *et al.,* 2011.

[211] NAS, 2000.

[212] U.S. EPA. 2001b. Responses to Comments of the Peer Review Panel and Public Comments on Methylmercury. Available on the Internet at *http://www.epa.gov/iris/supdocs/methpr.pdf.*

[213] U.S. EPA, 2001a. Water Quality Criterion for the Protection of the Human Health: MethylmercuryEPA–823–T–01–001, available at *http://water.epa.gov/scitech/swguidance/standards/criteria/aqlife/pollutants/methylmercury/index.cfm.*

[214] U.S. EPA–IRIS, 2001.

[215] Rice D, Schoeny R, Mahaffey K. 2003. ''Methods and Rationale for Derivation of a Reference Dose for Methylmercury by the U.S. EPA.'' Risk Analysis 23(1)107–115.

[216] NAS, 2000.

[217] Id.

[218] U.S. EPA, 2001b.

[219] U.S. EPA–IRIS, 2001.

[220] Schober Susan E, Sinks Thomas H, Jones Robert L, Bolger P Michael, McDowell Margaret, Osterloh John, Garrett E Spencer, Canady Richard A, Dillon Charles F, Sun Yu, Joseph Catherine B, Mahaffey Kathryn R. Blood mercury levels in U.S. children and women of childbearing age, 1999–2000. JAMA. 2003 Apr 2; 289(13): 1667–1674.

[221] Mahaffey, K.R., R.P. Clickner and R.A. Jeffries. 2009. Adult Women's Blood Mercury Concentrations Vary Regionally in the U.S.: Association with Patterns of Fish Consumption (NHANES 1999–2004). *Environ. Health Perspect.,* 117: 47–53.

men and women was 2 to 89.5 μg/L.[222] Note that some publications have reported Hg effects in U.S. populations at or below the current U.S. RfD.[223 224] Also, the EPA disagrees with the commenter stating all ocean fish throughout the world contain about the same amount of MeHg. Marine fish in commerce differ widely in Hg concentration by species, and fish within the same species but caught at different locations have variable amounts of Hg in their tissues.[225 226]

The EPA disagrees that there is a statistically discernible downward trend in the NHANES data on blood Hg. The EPA is unaware that a formal statistical analysis for temporal trends has been completed for NHANES data on blood Hg levels for the period 1999 to 2008. Mahaffey*et al.,* evaluating NHANES data collected 1999 to 2004 for women at child-bearing age, could ''not support the conclusion that there was a general downward trend in blood Hg concentrations over the 6-year study period.'' [227] However, the same publication noted that ''there was a decline in the upper percentiles reflecting the most highly exposed women'' having blood Hg concentration greater than established levels of concern. Visual observations of the data show a slight decrease in Hg blood level concentrations from 1999–2008 at the geometric mean, but this decrease may not be statistically significant. The EPA remains concerned that substantial numbers of women of childbearing age in the U.S. may have blood Hg levels that are equivalent to exposures at or above the RfD. While mean and 95th percentiles from recent NHANES data are below the blood Hg concentration equivalent to the RfD, blood levels for some portions of the population (high consumers of fish, for example) show exposures above this level. One study estimated very high blood Hg levels at the 99th percentile for females of child-bearing age.[228] Other published studies have shown that various population groups can have high blood Hg levels.[229 230 231 232 233] For example, one study found that 83 percent of the NHANES Asian population exceeded the RfD-equivalent blood mercury level.[234]

The EPA disagrees with the commenter regarding confounding by PCBs and lead. Exposure to MeHg in the Faroe Islands was largely from consumption of pilot whale meat; exposure to PCBs was found in the portion of the population who also consume whale blubber. Numerous analyses have shown neurobehavioral effects of PCBs; however, the effects of MeHg and PCB in the Faroe Islands study are separable.[235] The EPA also documented the independence of PCB and MeHg effects in the Faroe Islands population.[236] The National Institute of Environmental Health Sciences (NIEHS) concluded that both PCB and Hg had adverse effects.[237] The NAS concluded that there was no empirical evidence or theoretical mechanism to support the opinion that *in utero* Faroese exposure to PCBs exacerbated the reported MeHg effect.[238] A second set of analyses found that the effect of prenatal PCB exposure was reduced when the data were sorted into tertiles by cord PCB concentrations.[239] These analyses support a conclusion that there are measurable effects of MeHg exposure in the Faroese children that are not attributable to PCB toxicity. We also note that there was no report of lead exposure in the Faroe Islands population.

The EPA disagrees with the commenter's assertion that the connection between MeHg in fish and observed health effects is not understood due to evidence from the cited Texas study.[240] This is an exposure study rather than a study on measures of neurobehavioral or any other health endpoint. TCEQ noted that none of the Caddo Lake study participants had blood Hg levels above the benchmark dose level (BMDL) of 5.8 μg/L (one of the several used by EPA in the calculation of the MeHg RfD). The BMDL is not a ''no effect'' level. Rather it is an effect level for a percentage of the population. The EPA has noted in correspondence with TCEQ that, as an exposure study, the Caddo Lake study may be representative of the surrounding population; however, the sample size is very small. It is not appropriate to extrapolate from Caddo Lake to larger regional or national populations.

The EPA is aware of the possibility of both interactions among environmental contaminants and cumulative effects of pollutants that produce the same adverse endpoint. The EPA guidance exists for dealing with such scenarios.[241 242 243 244] The Agency's concern with the likelihood of human exposure to multiple contaminants is

[222] Hightower Jane M, Moore Dan. Mercury levels in high-end consumers of fish. Environ Health Perspect. 2003 Apr; 111(4): 604–608.

[223] Oken, E., Radesky, J.S., Wright, R.O., Bellinger, D.C., Amarasiriwardena, C.J., Kleinman, K.P., Hu, H., Gillman, M.W. 2008. Maternal fish Intake during Pregnancy, Blood Mercury Levels, and Child Cognition at Age 3 Years in a U.S. Cohort. *American Journal of Epidemiology, 167(10),* 1,171–1,181.

[224] Lederman, Sally Ann Robert L. Jones, Kathleen L. Caldwell, Virginia Rauh, Stephen E. Sheets, Deliang Tang, Sheila Viswanathan, Mark Becker, Janet L. Stein, Richard Y. Wang, and Frederica P. Perera. 2008. Relation between Cord Blood Mercury Levels and Early Child Development in a World Trade Center Cohort. *Environmental Health Perspectives* 118(8) 1085–1091.

[225] Hisamichi Y, Haraguchi K, Endo T. 2010. ''Levels of mercury and organochlorine compounds and stable isotope ratios in three tuna species taken from different regions of Japan.'' *Environ Sci Technol* 44(15): 5971–8.

[226] Sunderland EM. 2007. ''Mercury exposure from domestic and imported estuarine and marine fish in the U.S. seafood market.'' *Environ Health Perspect.* 115(2): 235–42. Epub 2006 Nov 20.

[227] Mahaffey, K.R., R.P. Clickner and R.A. Jeffries. 2009. Adult Women's Blood Mercury Concentrations Vary Regionally in the U.S.: Association with Patterns of Fish Consumption (NHANES 1999–2004). *Environ. Health Perspect.,* 117: 47–53.

[228] Tran, N.L., L. Barraj, *et al.,* 2004. ''Combining food frequency and survey data to quantify long-term dietary exposure: a methyl mercury case study.'' *Risk Anal* 24(1): 19–30.

[229] *Id.*

[230] Miranda, M.L., S. Edwards, *et al.,* 2011. ''Mercury levels in an urban pregnant population in Durham County, North Carolina.'' *Int J Environ Res Public Health* 8(3): 698–712.

[231] Hightower and Moore, 2003.

[232] Hightower, J.M., A. O'Hare, *et al.,* (2006). ''Blood mercury reporting in NHANES: identifying Asian, Pacific Islander, Native American, and multiracial groups.'' Environ Health Perspect 114(2): 173–175.

[233] McKelvey, W., R.C. Gwynn, *et al.,* 2007. ''A biomonitoring study of lead, cadmium, and mercury in the blood of New York city adults.'' Environ Health Perspect 115(10): 1435–1441.

[234] Hightower*et al.,* 2006.

[235] NAS, 2000.

[236] U.S. EPA, 2001a.

[237] National Institute of Environmental Health Sciences (NIEHS). 1998. Scientific issues relevant to assessment of health effects from exposure to methylmercury. Workshop organized by Committee on Environmental and Natural Resources (CENR) Office of Science and Technology Policy (OSTP), The White House, November 18–20, 1998, Raleigh, NC.

[238] NAS, 2000.

[239] Budtz-Jørgensen, E., N. Keiding, and P. Grandjean. 1999. Benchmark modeling of the Faroese methylmercury data. Final Report to U.S. EPA.

[240] DSHA, 2005.

[241] U.S. EPA. 1986. *Guidelines for the Health Risk Assessment of Chemical Mixtures.* U.S. Environmental Protection Agency, Office of Research and Development, Washington, DC September. EPA/630/R–98/002. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=2256.*

[242] U.S. EPA. 1999. *Guidance for Performing Aggregate Exposure and Risk Assessments.* U.S. Environmental Protection Agency, Office of Pesticide Programs, Washington, DC October. Available at *http://www.pestlaw.com/x/guide/1999/EPA-19991029A.html.*

[243] U.S. EPA. 2000a. *Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures.* U.S. Environmental Protection Agency, Risk Assessment Forum, Washington, DC EPA/630/R–00/002. Available at *http://www.epa.gov/ncea/raf/pdfs/chem_mix/chem_mix_08_2001.pdf.*

[244] U.S. EPA. 2003a. Framework for Cumulative Risk Assessment. Risk Assessment Forum, U.S. Environmental Protection Agency. Washington, DC EPA/630/P–02/001F. EPA/600/P–02/001F. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=54944.*

reflected in the multi-chemical scope of the rulemaking. However, the EPA focused the technical analyses supporting the proposed regulation on effects of individual pollutants rather than cumulative effects.

The EPA disagrees with commenters suggesting that the RfD-based HQ is inappropriate. The SAB ''agreed that EPA's calculation of a hazard quotient for each watershed included in the assessment is appropriate as the primary means of expressing risk,'' and that ''because the RfD from which the HQ is calculated is an integrative metric of neurodevelopmental effects of methylmercury, it constitutes a reasonable basis for assessing risk.'' [245]

The SAB also recommended that EPA revise the Hg Risk TSD to include additional qualitative discussion about uncertainty in the revised Hg Risk TSD. Specifically, the SAB recommended that EPA revise the Hg Risk TSD ''to better explain the methods and choices made in the analysis, and analytical results, and where the uncertainties lie.'' The SAB noted several uncertainties related to the RfD. The EPA agrees with this recommendation and included a more complete discussion of these uncertainties in the revised Hg Risk TSD.

The EPA disagrees that the IQ metric threshold is questionable. The SAB concluded that it was reasonable to consider a loss of >1 or >2 IQ points a public health concern. The SAB stated, ''The Panel agreed that if IQ loss is retained in the risk assessment despite these reservations, a loss of one or two points would be an appropriate benchmark.'' [246] The SAB further comments in their report: ''The consensus is that if IQ were to be used, then a loss of 1 or 2 points as a population average is a credible decrement to use for this risk assessment. This metric seems to be derived from the lead literature and was peer reviewed by the Clean Air Scientific Advisory Committee (U.S. EPA CASAC 2007).[247] Although its applicability to methylmercury is questionable, the size of the decrement is justified based on the extensive analyses available from the literature reviewed by CASAC.'' [248] As noted in other studies,[249] [250] a decrease of 1–2 points at the mean results in a much larger decrease in those with IQs that are much lower or higher than the mean.

Although EPA disagrees that the IQ results are too uncertain to rely upon, the EPA acknowledges that IQ is not the most sensitive neurodevelopmental endpoint affected by MeHg exposure, as also noted by the SAB. The SAB recommended that the IQ analyses be retained but be de-emphasized in the documentation underlying the final regulation. The SAB concluded, ''The Panel does not consider it appropriate to use IQ loss in the risk assessment and recommended that this aspect of the analysis be de-emphasized, moving it to an appendix where IQ loss is discussed along with other possible endpoints not included in the primary assessment. While the Panel agreed that the concentration-response function for IQ loss used in the risk assessment is appropriate, and no better alternatives are available, IQ loss is not a sensitive response to methylmercury and its use likely underestimates the impact of reducing methylmercury in water bodies.'' [251] The EPA is following the SAB's recommendation by deemphasizing the IQ analysis and placing that analysis in an appendix to the revised Hg Risk TSD.

The SAB, however, supported the use of the IQ dose-response function calculated by EPA in the Hg Risk TSD. The SAB noted, ''The function used came from a paper by Axelrad and Bellinger (2007) that seeks to define a relationship between methylmercury exposure and IQ. A whitepaper by Bellinger (Bellinger, 2005) [252] describes the sequence of steps in relating methylmercury exposure to maternal hair mercury and then that to IQ. The Mercury Risk TSD furthers notes that IQ has shown utility in describing the health effects of other neurotoxicants. These are appropriate bases for examining a potential impact of reducing methylmercury on IQ, but the SAB does not consider these compelling reasons for using IQ as a primary driver of the risk assessment.'' [253]

The EPA disagrees that the Agency has overstated or failed to review the scientific literature on cardiovascular effects from MeHg exposure. As summarized in the preamble to the proposal, the EPA stated that the NAS study concluded that ''Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.,* neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals.'' [254] The EPA also stated that additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects, and there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. In the future, the EPA may update the MeHg RfD and will review all of the relevant scientific literature available at that time, including data on all relevant endpoints, and weight of evidence for likelihood that MeHg produces specific effects in humans.

The EPA acknowledges the research regarding the effectiveness of fish advisories. However, the proposed regulation does not address the subject of fish advisories, consumer advice on fish or efficacy of such advice. The EPA rejects the commenter's speculation regarding whether the estimated IQ impacts for the regulation are real. Adverse effects of *in utero* Hg exposure have been reported in populations in the U.S.[255] [256] In another study on neurobehavioral effects of prenatal exposure to MeHg through maternal consumption of seafood, adverse effects are observed for MeHg even without controlling for fish consumption.[257] That study suggests that at normal Japanese dietary intake of MeHg and fish nutrients, the overall effect is adverse. While Japanese fish consumption and Hg exposure are both somewhat higher than the mean U.S. exposure, these levels are still within the distribution of U.S. consumers.

[245] U.S. EPA–SAB, 2011.

[246] U.S. EPA–SAB, 2011.

[247] U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA–SAB). 2007. *Clean Air Scientific Advisory Committee's (CASAC) Review of the 1st Draft Lead Staff Paper and Draft Lead Exposure and Risk Assessments.* EPA–CASAC–07–003. March. Available on the internet at *http://yosemite.epa.gov/sab/sabproduct.nsf/989B57DCD436111B852572AC0079DA8A/$File/casac-07-003.pdf.*

[248] U.S. EPA–SAB, 2011.

[249] Axelrad, D. A.; Bellinger, D. C.; Ryan, L. M.; Woodruff, T. J. 2007. ''Dose-response relationship of prenatal mercury exposure and IQ: An integrative analysis of epidemiologic data.'' *Environmental Health Perspectives,* 115, 609–615.

[250] Bellinger DC. 2005. *Neurobehavioral Assessments Conducted in the New Zealand, Faroe Islands, and Seychelles Islands Studies of Methylmercury Neurotoxicity in Children.* Report to the U.S. Environmental Protection Agency. EPA–HQ–OAR–2002–0056–6045.

[251] U.S. EPA–SAB, 2011.

[252] Bellinger, 2005.

[253] U.S. EPA–SAB, 2011.

[254] 76 FR 25001.

[255] Oken *et al.,* 2008.

[256] Lederman *et al.,* 2008.

[257] Suzuki, K., Nakai, K., Sugawara, T., Nakamura, T., Ohba, T., Shimada, M., Hosokawa, T., Okamura, K., Sakai, T., Kurokawa, N., Murata, K., Satoh, C., and Satoh, H. 2007. ''Neurobehavioral effects of prenatal exposure to methylmercury and PCBs, and seafood intake: neonatal behavioral assessment scale results of Tohoku study of child development.'' *Environ Res* 110, 699–704.

Moreover, many studies show that beneficial effects of fish on both cardiovascular and neurodevelopmental health are decreased by concomitant exposure to MeHg. Several studies describe one or more aspects of exposure to fish nutrients and MeHg.[258 259 260 261 262 263 264] Recent studies[265 266 267] and analyses indicate the potential for nutrients in fish (particularly marine fish) to mask some of the observed adverse effects of MeHg. Because EPA did not adjust for potential confounding by nutrients in marine fish and mammals, the benchmark doses used in the RfD derivation may be underestimated.

The EPA recognizes the potential for confounding of the effects of Hg on the developing nervous system by a range of nutrients and discusses this uncertainty in the revised Hg Risk TSD. Regarding selenium, the SAB commented that ''one SAB member suggests the use of blood markers of selenium-dependent enzyme function, noting that methylmercury irreversibly inhibits selenium-dependent enzymes that are required to support vital-but-vulnerable metabolic pathways in the brain and endocrine system. Impaired selenoenzyme activities would be observed in the blood before they would be observed in brain, but the effect is also expected to be transitory. The use of these measures is a minority view among the SAB members.''[268] The SAB did not express a consensus recommendation on adjustments to the risk estimates for exposure to selenium or other nutrients, noting that ''there is not enough known about their quantitative impact to support a recommendation of a re-analysis.''[269]

6. General Comments on Hg Risk Assessment

Comment: Several commenters generally supported the Hg risk assessment, but several other commenters generally disagreed with the Hg risk assessment. One supporter stated that EPA reasonably determined that Hg emissions pose a public health hazard, correctly requested peer review of Hg risk analysis and correctly concluded EGU-attributable MeHg poses a hazard to public health at watersheds when considering all sources of Hg deposition and U.S. EGUs alone. Two commenters noted that the contribution of U.S. EGUs to total Hg deposition can significantly contribute to hundreds of watersheds, and U.S. EGU deposition alone may endanger sensitive populations near many of these watersheds.

Several commenters claimed that overly conservative assumptions in the risk analysis render the results flawed and unreliable, including using CMAQ to model deposition, Mercury Maps, fish consumption rate and fish MeHg concentrations, overly stringent RFD, national-scale model, using poverty as a surrogate for subsistence fishing, assuming a subsistence fisher resides in most watersheds with fish tissue data, fishers only eat larger fish with high Hg concentrations, cooking loss adjustment, unrealistically high fish ingestion rates (a large fish meal every day), focused on the extremes of the distributions, cast many assumptions as an underestimate of the effect despite evidence to the contrary, and created inappropriate metrics for risk that show no improvement despite significant Hg emissions reductions in the U.S.

Several commenters cite Tetra Tech's analysis that assessed Hg risk using different consumption rates, cooking factor, mean fish tissue concentrations, and EGU-attributable Hg deposition only, which showed considerably fewer watersheds that exceed an HQ of 1 at 2016 deposition levels.

Several commenters claim that this regulation would not significantly reduce Hg exposure via fish consumption because EGU-attributable deposition is a small fraction of total deposition. One commenter stated that EPA's data shows Hg emissions from U.S. EGUs have little influence on fish Hg concentrations despite a reduction of 41 tons of Hg in the U.S. between 2005 and 2016. One commenter requested that EPA accurately describe the low health risks posed by utility hazardous air pollutant emissions. One commenter stated that EPA did not consider scientific information showing that there is no straightforward connection between Hg emissions from U.S. EGUs to the Hg level in fish, which is dependent upon many environmental factors, such as sunlight and organic matter, pH, water temperature, sulfate, bacteria, and zooplankton present in the ecosystem. One commenter stated that there is not any demonstrable evidence that anyone in the U.S. has suffered adverse health problems as a result of Hg emissions from coal-fired EGUs. One commenter stated that EPA's findings are similar to the 2000 findings where EPA found a plausible link between anthropogenic emissions of Hg from sources in the U.S. and MeHg in fish, and ''plausible'' is a euphemism for unproven.

Several commenters had recommendations for the Hg risk analysis. One commenter stated that more data from Florida should have been included because Florida is known to have a rich data set on fish Hg concentrations. One commenter stated that EPA should characterize general recreational angler fishers instead of subsistence fishers. One commenter claims that EPA made math errors in the Hg Risk TSD regarding the deposition in watersheds at specific percentiles. One commenter questioned EPA's policy metrics used to characterize Hg risk.

Several commenters stated that the Hg TSD is unclear and lacks detail, as noted by the SAB. One commenter stated that the SAB is critical of EPA's efforts, stating that the SAB found it difficult to evaluate the risk assessment based solely upon Hg Risk TSD and recommended that EPA transparently explain the methods and uncertainties. One commenter stated that because of insufficient review time and the lack of detail in the Hg Risk TSD, they could not assess key questions, such as the nation-wide representativeness of the fish tissue data.

One commenter stated the subset of watersheds considered in the analysis (*i.e.,* with fish tissue data) have clearly higher U.S. EGU-attributable deposition than the distribution of all watersheds.

One commenter stated EPA's reporting of IQ point loss is erroneous and not relevant to informing policy, and the U.S. EGU contribution to risk is marginal as evidenced by the null values for the 50th percentile watershed.

One commenter notes that U.S. EGU-attributable emissions of Hg have decreased significantly between 2005

[258] Grandjean P, Bjereve K, Wihe P, and Sterewald u. 2001a. ''UBirthweight in a fishing community: significance of essential fatty acids and marine food contaminants.'' *In. J. Epidemiol.* 30:1272–1278.

[259] Budtz-Jorgensen, E.; Grandjean, P.; Weihe, P. 2007. ''Separation of risks and benefits of 16 seafood intake.'' *Environmental Health Perspectives.* Vol. 115, 323–327.

[260] Choi *et al.,* 2008a.

[261] Choi *et al.,* 2008b.

[262] Oken *et al.,* 2008.

[263] Strain, J.J. *et al.,* 2008. Associations of maternal long chain polyunsaturated fatty acids, methyl mercury, and infant development in the Seychelles Child Development Nutrition Study.'' *Neurotoxicology.* 29(5): 776–782.

[264] Suzuki, *et al.,* 2007.

[265] Oken *et al.,* 2008.

[266] Choi AL, Cordier S, Weihe P, Grandjean P. 2008a. ''Negative confounding in the evaluation of toxicity: the case of methylmercury in fish and seafood.'' *Crit Rev Toxicol.* 2008;38(10):877–93.

[267] Choi AL, Budtz-Jørgensen E, Jørgensen PJ, Steuerwald U, Debes F, Weihe P, Grandjean P. 2008b. ''Selenium as a potential protective factor against mercury developmental neurotoxicity.'' *Environ Res.* May;107(1):45–52. Epub 2007 Sep 12.

[268] U.S. EPA–SAB, 2011.

[269] *Id.*

and 2016, but claims that this decrease does not appear to affect the risk results.

Response: The purpose of the Hg risk assessment is not to assess the magnitude of risk reduction under the proposed rule, but rather to estimate the magnitude of absolute risk attributable to U.S. EGUs currently and following implementation of other applicable CAA requirements. That said, any potential risk reductions following implementation of the MACT rule itself would likely reflect a number of factors besides the national average U.S. EGU deposition value cited by the commenter. These additional factors include: (a) Spatial gradients in the magnitude of absolute U.S. EGU-attributable Hg deposition, (b) spatial gradients in the magnitude of reductions in Hg deposition linked to the rule, (c) availability of measured fish tissue Hg levels in the vicinity of U.S. EGUs experiencing larger Hg emission reductions to support risk modeling, and (d) the potential for subsistence fishing activity at watersheds in the vicinity of U.S. EGUs experiencing larger reductions in Hg emissions (also required to support risk modeling). It is also important to point out that while the national average U.S. EGU-attributable Hg deposition (for the 2016 scenario—see revised Hg Risk TSD) is two percent, values range up to 11 percent for the 99th percentile watershed. This illustrates the substantial spatial variation in U.S. EGU-attributable Hg deposition, which translates into spatial variation in the magnitude of U.S. EGU-attributable subsistence fisher risk.

The SAB conducted a comprehensive peer review of all of EPA's assumptions in the Hg Risk TSD, and concluded that ''the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from Hg emitted from U.S. EGUs.'' [270] Furthermore, the SAB concluded, ''The SAB regards the design of the risk assessment as suitable for its intended purpose, to inform decision-making regarding an ''appropriate and necessary finding'' for regulation of hazardous air pollutants from coal and oil-fired EGUs, provided that our recommendations are fully considered in the revision of the assessment.'' [271] Although the SAB did indicate difficulty in evaluating the risk assessment based solely on the Hg Risk TSD, the panel obtained additional information from EPA through the peer review process and determined that ''the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs.'' [272] The primary advice of the SAB panel was that EPA should ''revise the Technical Support Document to better explain the methods and choices made in the analysis, and analytical results, and where the uncertainties lie.'' [273] The EPA has revised the Hg Risk TSD as part of the final rulemaking to address the SAB's recommendations and has made that revised Hg Risk TSD available in the rule docket.

The SAB concurred with EPA's analytical assumptions and overall study design for the Hg Risk TSD, including the RfD-based HQ approach, fish tissue data, 75th percentile size fish, Mercury Maps assumption, and consumption rates. Based on the SAB peer review, the EPA strongly disagrees with commenter statements that the results reported in the Hg Risk TSD are unreliable, overly conservative, extreme, inconsistent with EPA risk guidelines, or severely overstate risk based on the stated objectives of the analysis. The EPA has specifically addressed each of these assumptions in the previous sections of the preamble, and thus, does not repeat those responses here. Based on the review by the SAB, the EPA has accurately described the health risks posed by utility hazardous air pollutant emissions and disagrees with the commenter's statement that EPA has not provided any demonstrable evidence to show that adverse health risks exist. The EPA has applied peer reviewed modeling to estimate the deposition of Hg attributable to U.S. EGUs. The EPA asserts that these metrics demonstrate a clear hazard to public health from Hg emissions from U.S. EGUs.

The EPA thoroughly evaluated the Tetra Tech analysis. The EPA does not agree that the analysis by Tetra Tech uses assumptions that are ''more reasonable'', and the SAB agreed that all of EPA's assumptions in the Hg Risk TSD are reasonable and appropriate. The EPA asserts that Tetra Tech's analysis does not fully cover subsistence fishers likely to experience elevated U.S. EGU-related Hg exposure. Specifically, the risk estimate cited in the comment reflects application of a number of behavioral assumptions that provide significantly less coverage for higher risk subsistence fishers. Fish consumption surveys cited in the revised Hg Risk TSD suggest that higher percentile subsistence fishers eat more than twice the level of fish assumed by Tetra Tech. Tetra Tech's analysis also used the median fish tissue levels, but it is reasonable to assume that subsistence fishers would target somewhat larger fish to maximize the volume of edible meat per unit time spent fishing. Tetra Tech's analysis also assumed that cooking fish did not concentrate Hg, but a number of studies discussed in the revised Hg Risk TSD explicitly provide adjustment factors involving a higher unit concentration following preparation. Taken together, Tetra Tech's analysis does not address the stated goal of the risk assessment to assess the nature and magnitude of risk for those individuals likely to experience the greatest risk associated with exposure to U.S. EGU-attributable Hg.

The EPA disagrees with the commenter's assertion that this rule will not affect risks associated with Hg exposure. Hg from U.S. EGUs contributes to the levels of MeHg in fish across the country and consumption of contaminated fish can lead to increased risk of adverse health effects. The EPA has shown in the RIA (Chapter 5) that this rule will reduce Hg levels in fish.

The EPA acknowledges that U.S. EGUs contribute only a small fraction of total Hg deposition in the U.S. However, U.S. EGUs remain the largest emitter of Hg in the U.S., and the revised Hg Risk TSD shows that U.S. EGU-attributable Hg deposition results in up to 29 percent of modeled watersheds with populations potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. Mercury risk is increasing for exposures above the RfD, and as a result, any reductions in Hg exposures in locations where total exposures exceed the RfD can result in reduced risks. While these reductions in risk may be small for most populations and locations, in some watersheds and for some populations, reductions in risk may be greater.

The SAB also directly addressed the question of the nation-wide representativeness of the fish tissue MeHg data in the national Hg risk assessment. The SAB concluded, ''Although the SAB considers the number of watersheds included in the assessment adequate, some watersheds

[270] U.S. EPA–SAB, 2011.

[271] *Id.*

[272] *Id.*

[273] *Id.*

in areas with relatively high mercury deposition from U.S. EGUs were under-sampled due to lack of fish tissue methy[l]mercury data. The SAB encourages the Agency to contact states with these watersheds to determine if additional fish tissue methylmercury data are available to improve coverage of the assessment.'' [274] In response to the SAB's recommendations, the EPA obtained additional fish tissue sample data from several states, particularly Pennsylvania, Wisconsin, Minnesota, New Jersey, and Michigan. This additional data increased the total number of watersheds assessed in the analysis by 33 percent nationally. In Florida, the EPA assessed the Hg-related health risk for 40 watersheds. Because EPA did not find any additional fish tissue data for watersheds in Florida that could be incorporated into the analysis, the total number of watersheds in Florida assessed in the revised Hg Risk TSD remains the same as the Hg Risk TSD at proposal.

The EPA disagrees with the commenter that there were errors in the Hg Risk TSD. Instead, the commenter has misinterpreted how EPA calculated the percentiles. The percentile (and mean) values presented in Table ES–1 for total and U.S. EGU-attributable Hg deposition are not matched by watershed. In other words, the EPA queried for the percentiles (and mean) provided for total Hg deposition and presented those percentiles and then separately estimated the percentiles for U.S. EGU-attributable Hg. Therefore, the total and U.S. EGU-attributable values for the 99th percentile do not necessarily occur at the same watershed. The EPA has provided additional clarification in the revised Hg Risk TSD.

The EPA agrees with the commenter that MeHg levels in fish depend on a complicated set of environmental factors, and EPA acknowledged this in the revised Hg Risk TSD. Furthermore, the EPA acknowledges that total Hg fish tissue levels are not correlated with levels of total Hg deposition when looking across watersheds because this relationship is highly dependent on the methylation potential at the specific waterbody, which is affected by pH, sulfate deposition, turbidity, etc. However, several recent studies [275] [276] [277] show, and the SAB agrees, that it is appropriate for EPA to assume that changes in Hg deposition are linearly associated with *changes* in fish tissue concentration. In addition, the EPA agrees that the subset of watersheds in the risk analysis have somewhat higher U.S. EGU deposition than the distribution of all watersheds, but EPA disagrees that oversampling of high deposition watersheds is inappropriate.

The EPA does not agree that there is no improvement in fish Hg concentrations between 2005 and 2016, or that there will be no further improvement from decreasing Hg emissions from U.S. EGUs from the baseline in 2016. Although total risk from all Hg exposures will remain elevated in much of the U.S., much of that risk is associated with global, non-U.S. Hg emissions. U.S. EGUs remain the largest source of Hg emissions in the U.S., and reductions in those emissions will result in reduced Hg deposition in many highly impacted watersheds. As shown in the revised Hg Risk TSD, average U.S. EGU-attributable fish tissue Hg concentrations is estimated to decrease by 44 percent between 2005 and 2016. Although we did not remodel risk for the 2005 scenario in the revised Hg Risk TSD, we estimated at proposal that the total percent of modeled watersheds with populations potentially at-risk from Hg emissions from U.S. EGUs exceeding either risk metric (*i.e.*, U.S. EGUs alone or total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent) would decline from 62 percent in 2005 to 28 percent in 2016. This projected decline is primarily due to a combination of additional pollution control technologies installed to comply with federal regulations, such as CSAPR, and changing fuels, such as the shift to natural gas.

The EPA disagrees that IQ loss is erroneous or irrelevant to informing policy, but EPA has moved that analysis to an appendix in the revised Hg Risk TSD, per the SAB's recommendation. The EPA disagrees that the IQ effects at the 50th percentile watershed are useful in determining that there is not a hazard to public health because EPA's stated goal of the risk assessment was to focus on populations likely to experience relatively higher exposures to U.S. EGU-attributable Hg.

We also disagree with those commenters that point to the SAB's statements concerning the clarity of the Hg Risk TSD to suggest that the public did not have an ample opportunity to comment on the Hg risk assessment. Although it is correct that the SAB said the Hg Risk TSD was difficult to evaluate until EPA staff explained it at the public meeting in June 2011, we note that the commenters that assert that this issue amounts to a violation of CAA section 307(d) notice requirements made detailed technical comments, including many of the same comments as the SAB. Furthermore, the EPA provided notice of the peer review in the preamble to the proposed rule and a number of **Federal Register** notices advised the public of the peer review process and all the meetings were open to the public for comment and participation and the minutes of those meetings were posted on the SAB Web site. The minutes for the June 2011 meeting, during which EPA provided clarifying information, were available well within the public comment period for the proposed rule. For these reasons, we maintain that the public was provided an adequate opportunity to comment on the Hg risk assessment.

e. Non-Hg HAP Case Studies

1. Emissions for Non-Hg Case Studies

Comment: The commenters raised concerns about a wide variety of aspects of EPA's approach for emissions used for the non-Hg case studies, including the use of an arithmetic mean for computing emission factors for representing emissions of untested units, the suggestion of statistical outliers in the Cr test data, the claim that metals content of the fuel is an indicator of flawed test data, the statistical approaches used by EPA to create emission factors, the absence in EPA's approach of an equation that commenters claim better represents emissions values, that EPA's approach to estimate Cr(VI) is flawed, and the lack of coal rank as a delineating factor for emission factor calculation. The commenters also suggested that EPA should revise stack parameters used for the case studies based on better available data.

Response: In response to the comments on the emission factors, the EPA has undertaken additional analysis to address all commenter concerns. The EPA disagrees with commenter's criticisms of emission factors based on arithmetic means, and EPA demonstrates that the use of an arithmetic mean provides the most representative result. The EPA analysis has found that the geometric mean approach recommended by the commenter always under predicts actual emissions by an average of more than seventy percent. The EPA agrees with commenters' recommendations to use statistical outlier tests, but has applied tests different from those suggested by the commenters. As further explained in the response to comments document in the docket, this approach did not eliminate the Cr test data from the Cr

[274] U.S. EPA–SAB, 2011.

[275] Orihel *et al.*, 2007.

[276] Orihel *et al.*, 2008.

[277] Harris *et al.*, 2007.

emission factors used for some of the case study emissions.

The EPA disagrees with commenters' assertions that the metal content of the coal is a basis for invalidating the test results of high Cr emissions. The identification of sources whose measured emissions do not match the commenters' preconceived idea of emissions behavior is not surprising. There are many possible explanations for these differences. For example, the inconsistency between the test data and the coal analysis could be due to any number of reasons including unrepresentative coal sampling, control device problems, degradation of the refractory, or sampling contamination. The idea that test data should be discarded because it does not match initial expectations is unfounded.

The EPA disagrees with the commenter recommendations for using an equation from AP–42, developed in part by the commenters. Based on analyses of metal emissions measured at the site compared to statistically predicted estimates, the EPA concluded that measured emissions test data better predict actual emissions, and emission factors based on the arithmetic mean are a reasonable method to estimate emissions when test data are not available. The EPA analysis of the ICR data has found that the emissions equation recommended by the commenter is not a good predictor of actual EGU emissions. The EPA also disagrees with commenters' concerns about the assumption that 12 percent of the Cr will be Cr(VI) for every coal-fired unit, which was specifically supported by the peer review on the approach for estimating cancer risks associated with Cr and Ni emissions. The EPA disagrees with the commenter's assertion that any impact of scrubbers will impact the case study analyses. In EPA's revised case study analysis, 6 facilities have risk greater than 1 in a million, and of these, four facilities have Cr as the risk driver (James River, Conesville, TVA Gallatin, and Dominion—Chesapeake Bay). For these facilities, none of the units contributing the bulk of the Cr emissions have scrubbers according to the data provided to EPA by those facilities, so scrubber impacts on Cr speciation is not relevant to EPA's conclusions based on the non-Hg case studies. In any case, the EPA disagrees with the commenter's conclusions about the impacts of scrubbers on Cr speciation and provides evidence that impacts of scrubbers on Cr speciation can have the opposite effect on Cr(VI) fractions, concluding that EPA's 12 percent assumption is somewhat conservative.

The EPA also disagrees that coal rank must be a factor in computing Cr emission factors for use in the case studies. The EPA's analysis has demonstrated that coal rank appears to play no role in non-Hg metals emissions. The EPA's newly revised emissions factor development procedures can isolate and compare subgroups based on control device type or coal rank; the ICR data were subjected to these tests and no statistical significance was found between coal rank groups.

Finally, the EPA agrees with one commenter's recommendations on revised stack parameters for the case studies and has included these revisions in the case study modeling for the final rule.

2. General Comments on Non-Hg Risk Case Study

Comment: One commenter stated that EPA's case study assessment reaffirms the need to regulate HAP emitted by both coal and oil-fired EGUs. The commenter noted that over 40 percent of the case studies conducted by EPA to quantify health hazards associated with the inhalation of non-Hg HAP indicated a cancer risk greater than or equal to the one in a million threshold level required to delist a source category under CAA section 112.

One commenter stated that EPA's case study assessment might be flawed by the use of ''beta'' tests versions of the AERMOD meteorological preprocessors (AERMINUTE and AERMET). The commenter obtained from EPA the meteorological data used for EPA's assessment of the Conesville facility and processed these data with EPA's current regulatory versions of these preprocessors, which differ from the beta version. According to the commenter, a comparison of the hourly wind speed and hourly wind direction data produced by the beta preprocessor and by current EPA preprocessors revealed numerous and often substantial disparities.

One commenter stated that EPA's finding that only three coal-fired facilities and one oil-fired facility out of roughly 440 coal-fired facilities and 97 oil-fired facilities in the U.S. indicated risk greater than one-in-a-million supports a finding that it is ''appropriate'' to regulate those four and not the other 537. Another commenter stated that EPA found only a ''few'' facilities that have estimated maximum cancer risks in excess of one in a million, and that this does not justify regulating all non-Hg HAP for all sources in this category.

One commenter stated that EPA's discussion in the preamble to the proposed rule misleads the reader into believing that non-Hg HAP emissions from EGUs are associated with serious human health effects. According to the commenter, the EPA's discussion of the effects associated with excessive exposure to an individual HAP would lead the reader to believe that those effects inevitably occur from EGU emissions because EGU emissions have trace amounts of non-Hg HAP.

One commenter stated that with the assumptions in the Utility Study, both in terms of conservative scientific estimates and overestimated amounts of oil burned by these units, the EPA concluded that the risks from oil-fired units would result in only one new cancer case every 5 years. The commenter does not believe that this level of risk warrants regulation under CAA section 112(n)(1)(A).

Several commenters stated that even if the additional studies EPA performed were accurate, they hardly demonstrate that it is necessary and appropriate to regulate coal-fired EGU HAP under CAA section 112 because three sites nationwide show risks greater than one in a million, with the highest at eight in a million.

One commenter stated that the highest cancer risk estimated for coal-fired EGUs is still within the acceptable range used by EPA in other programs and is also far less than the background exposure risks the average person experiences. The background risk of developing cancer in a lifetime is approximately one in three (0.33). According to EPA's own data, the predicted added cancer risk of exposure to HAP from U.S. EGUs would change the background risk from 0.33 to 0.330001. This level of change is so minimal that it could not be observed in any health effects study that might be conducted.

One commenter stated that EPA conducted a health risk assessment on a limited number of facilities and found a ''few'' facilities that have estimated maximum cancer risks in excess of one in a million. The commenter stated that, based on this limited health risk assessment, the EPA apparently decided that they were justified to regulate all non-Hg HAP for all sources in this category.

Several commenters stated that EPA's assumption implies that a person stays exactly at the center of a census tract for 70 years and that a unit will operate in exactly the same manner for 70 years is unrealistic. The commenters suggest that Tier 3 risk assessment is warranted or a lifetime exposure adjustment is needed.

One commenter asserts that because the alleged health benefits are derived from total exposure, the EPA should explain how its numerical emission limit units, which would not directly restrict total exposure if heat inputs increase, redress this health concern. In its preamble, the EPA simply notes that its emission limit units are consistent with, and allow for simple comparison to, other regulations.

One commenter questioned whether acid gas emissions limits for oil-fired units are ''appropriate'' or ''necessary'' because EPA's new technical analyses do not indicate a health concern from acid gas emissions from oil-fired units. According to the commenter, the EPA identifies Ni as the main HAP of concern from oil-fired units, even though cancer-related inhalation risks were well below the RfCs and EPA states that significant uncertainty remains as to whether those emissions present a health concern.

Response: The EPA agrees with the commenter that the non-Hg HAP risk assessment confirms the appropriate and necessary finding.

The EPA disagrees that EPA's case study assessment is flawed by the use of beta versions of AERMINUTE and AERMET. The EPA remodeled the case study facilities using the current versions of AERMINUTE (version 11059), AERMET (version 11059), and AERMOD (version 11103). Although there were differences in the number of calm and missing winds in the current AERMINUTE/AERMET output compared to the beta version, the resulting risks differed by less than two percent, on average. For Conesville, which had the largest difference in calms between the beta and current versions of AERMINUTE/AERMET, the risks differed by three percent. For the final rule, the case study facilities have been modeled with the current available versions of AERMINUTE, AERMET, and AERMOD.

The EPA disagrees with the commenter that having only a few case study facilities exceeding one in a million risk invalidates the ''appropriate finding''. The 16 facilities EPA selected as case studies for assessment may not represent the highest-emitting or highest-risk sources. Although case study facility selection criteria included high estimated cancer and non-cancer risks using the 2005 NEI data, high throughput, and minimal emission control, another necessary criterion was the availability of Information Collection Request (ICR) data for the EGUs at those facilities (or for similar EGUs at other facilities). Because the ICR data were collected for the purpose of developing the MACT standards, the ICR was targeted towards better performing sources for non-Hg metal HAP, acid gas HAP, and organic HAP, with a smaller set of random recipients. Therefore, facilities for which ICR data were available may not represent the highest-emitting sources. The EPA's assessment of the case study facilities for the proposed rule concluded that three coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million. For the final rule, revisions were made to the 16 case studies based on comments received, and the results indicate that 5 coal-fired facilities and 1 oil-fired facility had estimated lifetime cancer risks greater than 1 in a million. The EPA maintains that its finding that more than 30 percent of the case study facilities had a cancer risk greater than one in a million is sufficient to support the appropriate finding.

The EPA disagrees with the commenter's assertion that the health effects associated with exposures to non-Hg HAP from U.S. EGUs are mischaracterized in the preamble to the proposed rule. The discussion of the health effects of non-Hg HAP provided in the preamble includes general information on the potential health effects associated with a broad range of exposure concentrations (from low to high levels) of the various non-Hg HAP (some of which have been determined to be carcinogenic to humans) based on peer reviewed scientific information extracted from priority sources such as IRIS, Cal EPA and ATSDR health effects assessments.

The EPA disagrees with the commenter's characterization of the Utility Study. The Utility Study represented the highest-quality factual record of information available at the time regarding EGU emissions and risks. Further, the EPA's revised risk assessments of 16 case studies, performed with more recent data and refined scientific methods, indicate that there are six U.S. EGU facilities that pose estimated inhalation cancer risks greater than 1 in a million. The EPA maintains that the findings of the case studies are one element that independently supports our determination that it remains appropriate and necessary to regulate EGUs under CAA section 112.

The EPA does not agree with the commenter who suggested that EPA should interpret the results of the non-Hg HAP risk analysis in the context of background cancer risk. As explained in the preamble to the proposed rule, the EPA reasonably looked to the cancer risk threshold established under CAA section 112(c)(9)(B)(1) for delisting a source category as an indicator of the level of cancer risk that was appropriate to regulate under CAA section 112. The commenters comparison of the cancer risk from EGUs as compared with the risk of contracting cancer from unknown sources is not the standard Congress established for evaluating HAP emission risk and the commenter has provided no support for its contention that the Agency should evaluate risk in that manner. The EPA maintains that the analysis was reasonable.

The EPA does not agree with the commenter's implication that EPA must make a facility-specific finding for each HAP for each source and then only regulate individual EGU facilities for the individual HAP that identified as causing an identified hazard to public health or the environment. That approach is not required under CAA section 112(n)(1) or anywhere under CAA section 112, and it would be virtually impossible to undertake such an effort. For these reasons, the EPA does not agree with the commenter and maintains that the appropriate and necessary finding is reasonably supported by the record and consistent with the statute for all the reasons set forth in the preamble to the proposed rule and this final action.

The EPA disagrees that an exposure adjustment is needed to account for conditions changing over 70 years because it runs counter to the long-standing approach that EPA has taken to estimate the maximum individual risk, or MIR. The MIR is defined by EPA's Benzene NESHAP regulation of 1989 [278] and codified by CAA section 112(f) as the lifetime risk for a person located at the site of maximum exposure 24 hours a day, 365 days a year for 70 years (*e.g.*, census block centroids). The MIR is the metric associated with the determination of whether or not a source category may be delisted from regulatory consideration under CAA section 112(c)(9). The MIR is the risk metric used to characterize the inhalation cancer risks associated with the case study facilities. The EPA used the annual average ambient air concentration of each HAP at each census block centroid as a surrogate for the lifetime inhalation exposure concentration of all the people who reside in the census block. The EPA has used this approach to estimate MIR values in all of its risk assessments to

[278] 54 FR 38044.

support risk-based rulemakings under CAA section 112 to date.

The EPA disagrees with the commenter's assertion that the numerical emission limits being promulgated in today's final rule must be justified on their ability to redress the health concerns that were identified as the basis for regulating EGUs. The emission limits in today's rule are technology-based, as prescribed under CAA section 112, and do not need to be justified based on their ability to protect public health. Regarding potential health concerns, the EPA has up to 8 years after the promulgation of the technology-based emission limits for EGUs to determine whether the regulations protect public health with an ample margin of safety. If the regulations do not, the CAA directs EPA to promulgate additional more stringent standards (within the prescribed 8 years) to achieve the appropriate level of public health protection.

Furthermore, the EPA reasonably concluded that it was appropriate and necessary to regulate oil-fired EGUs in 2000, and EPA confirmed that conclusion was proper with the analysis set forth in the preamble to the proposed rule. Certain commenters question the determination based on their views of how the Agency can and should exercise its discretion. The EPA disagrees with these commenters and stands by the determination for the reasons set forth in the preamble to the proposed rule. The EPA also stands by the determination that the maximum cancer risks posed by emissions of oil-fired EGUs are greater than one in a million, due primarily to emissions of Ni compounds. Based on our analysis, we are unable to delist oil-fired EGUs.

3. Ni Risk

Comment: Several commenters stated that the assumptions regarding the speciation and carcinogenic potential of Ni compounds used in EPA's inhalation risk assessment of the case study facilities are overly conservative and likely to overstate the risks. With respect to Ni speciation, the commenters stated that there are substantial uncertainties regarding the species of Ni being emitted and the risk of such emissions, and that EPA has made ultraconservative assumptions aimed at overestimating the risk. The commenters stated that assigning the same carcinogenic potency of Ni subsulfide to other forms of Ni is overly conservative and inconsistent with the best available evidence.

Response: The EPA disagrees with the commenters' assertion that it is impossible to give an accurate assessment of the risks to human health from Ni emissions from EGUs, and maintains that its assessment of the potential inhalation risks from EGU emissions of Ni compounds is scientifically valid, reasonable, and based on the best-available current scientific understanding. To that end, in July 2011, the EPA completed an external peer review (using three independent expert reviewers) of the methods used to evaluate the risks from Ni and Cr compounds emitted by EGUs.[279] There were two charge questions relating to Ni in that review. First, do EPA's judgments related to speciated Ni emissions adequately take into account available speciation data, including recent industry spectrometry studies? Second, based on the speciation information available and what is known about the health effects of Ni compounds, and taking into account the existing URE values (*i.e.,* values derived by the Integrated Risk Information System,[280] California Department of Health Services,[281] and the Texas Commission on Environmental Quality [282]), which of the following approaches to derive unit risk estimates would result in a more accurate and defensible characterization of risks from exposure to Ni compounds?

1. To continue using the same approach as that developed for use in the 2000 NATA, which consists of using the IRIS URE for nickel subsulfide and assuming that nickel subsulfide constitutes 65 percent of the mass emissions of all Ni compounds.

2. To consider a more health-protective approach, based on the consistent views of the most authoritative scientific bodies (*i.e.,* NTP in their 12th ROC, IARC, and other international agencies) that consider Ni compounds to be carcinogenic as a group.

3. To make the same assumptions as in option 2, but considering alternative UREs derived by the CDHS or TCEQ.

In responding to these peer review questions, two of the reviewers agreed with the views of the most authoritative scientific bodies, which consider Ni compounds carcinogenic as a group. These reviewers, therefore, did not focus on the availability of Ni speciation profile data. The third reviewer recommended that EPA review several manuscripts on Ni speciation profiles showing that sulfidic Ni compounds (which the reviewer considered as the most potent carcinogens) are present at low levels in emissions from EGUs.

Nickel and Ni compounds have been classified as human carcinogens by national and international scientific bodies including the IARC,[283] the World Health Organization,[284] and the European Union's Scientific Committee on Health and Environmental Risks.[285] In their *12th Report of the Carcinogens,* the NTP has classified Ni compounds as known to be human carcinogens based on sufficient evidence of carcinogenicity from studies in humans showing associations between exposure to Ni compounds and cancer, and supporting animal and mechanistic data. More specifically, this classification is based on consistent findings of increased risk of cancer in exposed workers, and supporting evidence from experimental animals that shows that exposure to an assortment of Ni compounds by multiple routes causes malignant tumors at various organ sites and in multiple species. The *12th Report of the Carcinogens* states that the ''combined results of epidemiological studies, mechanistic studies, and carcinogenesis studies in rodents support the concept that Ni compounds generate Ni ions in target cells at sites critical for carcinogenesis, thus allowing consideration and evaluation of these compounds as a single group''.[286] Although the precise Ni compound (or compounds) responsible for the carcinogenic effects in humans is not always clear, studies indicate that Ni sulfate and the combinations of Ni sulfides and oxides encountered in the Ni refining industries cause cancer in humans. There have been different views on whether or not Ni compounds, as a group, should be considered as carcinogenic to humans. Some authors

[279] U.S. EPA, 2011c.

[280] *U.S.* EPA, 1991.

[281] California Department of Health Services (CDHS) 1991. Health Risk Assessment for Nickel. Air Toxicology and Epidemiology Section, Berkeley, CA. Available online at *http://oehha.ca.gov/air/toxic_contaminants/html/Nickel.htm.*

[282] Texas Commission on Environmental Quality (TCEQ), 2011. Development Support Document for nickel and inorganic nickel compounds. Available online at *http://www.tceq.state.tx.us/assets/public/implementation/tox/dsd/final/june11/nickel_&_compounds.pdf.*

[283] International Agency for Research on Cancer (IARC), 1990. IARC monographs on the evaluation of carcinogenic risks to humans. *Chromium, nickel and welding.* Vol. 49. Lyons, France: International Agency for Research on Cancer, World Health Organization Vol. 49:256.

[284] International Labour Organization/United Nations Environment Programme, World Health Organization (WHO), 1991. Nickel. In Environmental Health Criteria No 108 Geneva.

[285] European Commission, Scientific Committee on Health and Environmental Risks (SCHER), 2006. Opinion on: Reports on Nickel, Human Health part. SCHER, 11th plenary meeting of 04 May 2006 *http://ec.europa.eu/health/ph_risk/committees/04_scher/docs/scher_o_034.pdf.*

[286] NTP, 2011.

believe that water soluble Ni, such as Ni sulfate, should not be considered a human carcinogen, based primarily on a negative Ni sulfate 2-year NTP rodent bioassay (which is different than the positive 2-year NTP bioassay for Ni subsulfide).[287] [288] [289] Although these authors agree that the epidemiological data clearly supports an association between Ni and increased cancer risk, they sustain that the data are weakest regarding water soluble Ni. A recent review [290] highlights the robustness and consistency of the epidemiological evidence across several decades showing associations between exposure to Ni and Ni compounds (including Ni sulfate) and cancer.

Based on the views of the major scientific bodies mentioned above, and those of expert peer reviewers that commented on EPA's approaches to risk characterization of Ni compounds, the EPA considers all Ni compounds to be carcinogenic as a group and does not consider Ni speciation or Ni solubility to be strong determinants of Ni carcinogenicity. With regards to non-cancer effects, comparative quantitative analysis across Ni compounds indicates that Ni sulfate is as toxic or more toxic than Ni subsulfide or Ni oxide.[291] [292]

Regarding the second charge question, two of the reviewers suggested using the URE derived by TCEQ for all Ni compounds as a group, rather than the one derived by IRIS specifically for Ni subsulfide. The third reviewer did not comment on alternative approaches. The EPA decided to continue using 100 percent of the current IRIS URE for Ni subsulfide because IRIS values are at the top of the hierarchy with respect to the dose response information used in EPA's risk characterizations, and because of the concerns about the potential carcinogenicity of all forms of Ni raised by the major national and international scientific bodies.

Nevertheless, taking into account that there are potential differences in toxicity and/or carcinogenic potential across the different Ni compounds, and given that there have been two URE values derived for exposure to mixtures of Ni compounds that are 2–3 fold lower than the IRIS URE for Ni subsulfide, the EPA also considers it reasonable to use a value that is 50 percent of the IRIS URE for Ni subsulfide for providing an estimate of the lower end of a plausible range of cancer potency values for different mixtures of Ni compounds.

4. Cr Risk

Comment: One commenter stated there are several problems with EPA's analysis related to the fact that Cr emissions were evaluated as being entirely Cr(VI). The commenter stated that not all of the emitted Cr will remain in the hexavalent form by the time it reaches the target population, and that some may be converted to the much less toxic (and noncarcinogenic) trivalent species. The commenter also stated that the concentration levels considered in the case study assessment are far below occupational levels. The commenter concluded that EPA's cancer estimates should, therefore, be looked on with some skepticism. Another commenter stated that EPA's estimate of 12 percent Cr(VI) from coal-fired EGUs is unsupported, and that EPA failed to recognize that Cr(VI) is highly water-soluble and is easily reduced to Cr(III) in the presence of SO_2 in a low pH environment. The resulting Cr(III) would be expected to precipitate out in a FGD. The commenter stated that the actual amount of Cr(VI) that would be present in the emissions from an EGU with a wet scrubber is likely to be far lower than the 12 percent estimate made by EPA.

Several commenters questioned the validity of the chronic inhalation study by EPA because of (1) the use of surrogate speciated Cr emissions data instead of actual emissions data, (2) the assumption that units were run 100 percent of the time which is impossible, (3) dispersion modeling was used that is biased towards over predicting downwind impacts, and (4) estimated ambient concentrations were utilized as substitutes for real exposure concentrations for all people within a census block.

Response: The EPA disagrees with the commenters' assertion that all Cr was considered to be hexavalent. As discussed in ''Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds,'' [293] existing test data for utility and industrial boilers indicate that Cr(VI) is, on average, 12 percent of total Cr from coal-fired boilers. This document underwent peer review by three external reviewers, and all three reviewers considered EPA's use of the values to be reasonable given the limited data available for Cr speciation profiling. The EPRI inhalation study for coal-fired boilers also used the 12 percent value.

The EPA also disagrees that units were assumed to operate 100 percent of the time. The dispersion modeling performed for the case study facilities used hourly heat input as a temporalization factor for estimating hourly emissions, and in some cases hourly heat inputs (and emissions) were zero or very low. The commenter provided no data or information to support their claim that the dispersion modeling EPA used is biased towards overestimating downwind impacts.

The EPA disagrees with the commenters' assertion that ''real exposure concentrations for all people within a census block'' must be considered because it runs counter to the long-standing approach that EPA has taken to estimate the maximum individual risk, or MIR. The MIR is defined by EPA's Benzene NESHAP regulation of 1989 [294] and codified by CAA section 112(f) as the lifetime risk for a person located at the site of maximum exposure 24 hours a day, 365 days a year for 70 years (*e.g.,* census block centroids). The MIR is the metric associated with the determination of whether or not a source category may be delisted from regulatory consideration under CAA section 112(c)(9). The MIR is the risk metric used to characterize the inhalation cancer risks associated with the case study facilities. The EPA used the annual average ambient air concentration of each HAP at each census block centroid as a surrogate for the lifetime inhalation exposure concentration of all the people who reside in the census block. The EPA has used this approach to estimate MIR values in all of its risk assessments to support risk-based rulemakings under CAA section 112 to date.

5. Acid Gas Risk

Comment: One commenter stated that acid gas emissions from oil-fired EGUs are not of the magnitude that triggered EPA's decision to regulate EGUs in general, raising the question of whether reduction (or even total elimination) of acid gas emissions from oil-fired EGUs could have any significant effect on EPA's goals of reducing non-cancer

[287] Oller A. Respiratory carcinogenicity assessment of soluble nickel compounds. Environ Health Perspect. 2002, 110:841–844.

[288] Heller JG, Thornhill PG, Conard BR. New views on the hypothesis of respiratory cancer risk from soluble nickel exposure; and reconsideration of this risk's historical sources in nickel refineries. J Occup Med Toxicol. 2009, 4:23.

[289] Goodman JE, Prueitt RL, Thakali S, and Oller AR. The nickel iron bioavailability model of the carcinogenic potential of nickel-containing substances in the lung. Crit Rev Toxicol. 2011, 41:142–174.

[290] Grimsrud TK and Andersen A. Evidence of carcinogenicity in humans of water-soluble nickel salts. J Occup Med Toxicol. 2010. 5:1–7. Available online at *http://www.ossup-med.com/content/5/1/7.*

[291] Haber LT, Allen BC, Kimmel CA. Non-Cancer Risk Assessment for Nickel Compounds: Issues Associated with Dose-Response Modeling of Inhalation and Oral Exposures. Toxicol Sci. 1998. 43:213–229.

[292] NTP, 1996.

[293] U.S. EPA, 2011c.

[294] 54 FR 3804.

health risk or acidification of sensitive ecosystems in the U.S.

Several commenters stated that acid gas concentrations estimated in the case study facility assessment and the Utility Study do not exceed human health thresholds of concern. Two commenters stated that HCl emissions are negligible compared to other primary emissions (such as SO_2) that can lead to potential acidification of ecosystems.

Response: We do not agree with commenter's implication that Congress intended EPA to regulate only those HAP emissions from U.S. EGUs for which an appropriate and necessary finding is made, and commenter has cited no provision of the statute that states a contrary position. The EPA concluded that we must find it ''appropriate'' to regulate EGUs under CAA section 112 if we determine that a single HAP emitted from EGUs poses a hazard to public health or the environment. If we also find that regulation is necessary, the Agency is authorized to list EGUs pursuant to CAA section 112(c) because listing is the logical first step in regulating source categories that satisfy the statutory criteria for listing under the statutory framework of CAA section 112. *See New Jersey,* 517 F.3d at 582 (stating that ''[s]ection 112(n)(1) governs how the Administrator decides whether to list EGUs * * *''). As we noted in the preamble to the proposed rule, D.C. Circuit precedent requires the Agency to regulate all HAP from major sources of HAP emissions once a source category is added to the list of categories under CAA section 112(c). *National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633 (D.C. Cir. 2000). 76 FR 24989. The EPA discusses in the preamble to the proposed rule and this final action its concerns with HCl and other acid gas HAP emissions from EGUs and the Agency's approach for establishing section 112(d) standards for acid gas HAP.

6. EPRI Risk Analysis

Comment: Two commenters stated that a comprehensive tiered inhalation risk assessment (the EPRI study) using EPA-prescribed methods with improved emission factors, fuel data, and confirmed stack parameters did not identify significant health risks (cancer or non-cancer) among U.S. coal-fired power plants (as they existed in 2007). The commenters noted that these results contrast with those presented by EPA for its non-Hg case studies on 16 (15 coal-fired) power plants. The commenters stated that several issues appear to underlie these differences, indicating the need for EPA to reevaluate its assessment and to undertake more refined (Tier 3) risk assessment for any facility of concern. Several commenters stated that for non-Hg HAP EPA produced one study on chronic inhalation risk assessment that identified three sites with cancer risks greater that one in a million for Cr(VI), which was authored by EPA staff and not peer reviewed. One commenter stated that EPA study is based on misinformation and overestimates assumptions, and that EPA has no data demonstrating health impacts from EGU emissions of non-Hg HAP, or the benefit from reducing such emissions. Two commenters stated that no benefits will be derived from the non-Hg HAP emission reductions associated with the proposed rule because no non-Hg HAP health risks were proven, and that no showing was made that EGU non-Hg HAP emission levels reach levels associated with adverse health effects. Another commenter stated that EPA must complete a comparable and separate national-scale risk assessment for non-Hg metals in order to determine appropriateness of proposing emissions standards for non-Hg metals.

Response: The commenters are incorrect in the assertion that EPA's case studies were performed with less rigor than the EPRI analysis. The EPRI analysis used a tiered approach to risk assessment, beginning with Tier 1 using EPA's SCREEN3 dispersion model on all 470 coal-fired power plants in the U.S., and following with Tier 2 with EPA's Human Exposure Model (which uses the AERMOD dispersion model) for plants with higher risks from the Tier 1 modeling. Although tiered risk assessment is an appropriate approach, the Tier 2 modeling could have been more refined. For example, more meteorological data could have been used and building downwash could have been considered. The EPRI analysis ostensibly concluded that the Tier 2 modeling with HEM was conservative, and that because the modeled risks did not exceed certain thresholds, no further refinement was necessary. However, such refinements could result in higher modeled risks than those from the commenter's Tier 2 modeling.

The EPA's dispersion modeling of the case study facilities was actually performed with a greater degree of refinement than the EPRI analysis, and was consistent with EPA's *Guideline on Air Quality Models.*[295]

In contrast to the approach used in the EPRI analysis, the EPA used:

(1) 5 years of recent meteorological data from the weather station nearest to each facility, rather than one year of meteorological data. This is more representative of long-term (*i.e.,* lifetime) exposures and risks.

(2) Temporally-varying emissions based on continuous emissions monitoring data, rather than assuming a constant emission rate for each facility throughout the entire simulation.

(3) Building downwash, where appropriate.

(4) The latest version of AERMOD [version 11103].

The EPA's assessment of the case study facilities for the proposed rule concluded that three coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million. For the final rule, revisions were made to the case studies based on comments received, and the results indicate that five coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million.

Regarding peer review, the risk assessment methodology used by EPA for the case studies was consistent with the method that EPA uses for assessments performed for Risk and Technology Review rulemakings, which underwent peer review by the Science Advisory Board in 2009.[296] The SAB issued its peer review report in May 2010. The report generally endorsed the risk assessment methodologies used in the program. In addition, in July 2011, the EPA completed a letter peer review of the methods used to develop inhalation cancer risk estimates for Cr and Ni compounds.

f. Ecosystem Impacts From HAP

Comment: Two commenters assert that EPA is not justified in regulating acid gases based on concern about the potential that acid gases contribute to ecosystem acidification rather than concerns about hazards to public health. The commenters further claim that HCl's contribution to ecosystem acidification is de minimis. The commenters point out that EPA acknowledges uncertainty in quantification of acidification and EPA relies on recently published research[297] that is irrelevant to the question since it is based on research conducted in the peat bog ecosystem in the United Kingdom. Another commenter calls attention to several new studies published in a special issue of the

[295] Appendix W to 40 CFR Part 51.

[296] U.S. EPA–SAB, 2010.

[297] Evans, Chris D., Don T. Monteith, David Fowler, J. Neil Cape, and Susan Brayshaw. 2011. ''Hydrochloric Acid: An Overlooked Driver of Environmental Change.'' *Environmental Science & Technology* 45 (5), 1887–1894.

journal *Ecotoxicology* devoted to the effects of MeHg on wildlife.

Response: Although EPA agrees that quantification of acidification effects has remaining uncertainty, the science and methodology has progressed in recent years. Based on recent peer reviewed research including Evans et al.,[298] acid gases can significantly contribute to acidification. The EPA published a comprehensive risk assessment of acidification effects of nitrogen and sulfur deposition [299] and a policy assessment.[300] Given the extent and importance of the sensitive ecosystems evaluated in the review of nitrogen and sulfur deposition any substance that contributes to further acidification must be considered to be affecting the public welfare. The EPA disagrees that the peer reviewed study mentioned by commenter by Evans *et al.,* (2011) is not relevant to U.S. ecosystems. The paper presents evidence that show (1) that HCl is highly mobile in the environment, transferring acidity easily through soils and water, (2) that HCl can transport longer distances than previously thought (given its presence in remote ecosystems, and (3) that it can be a larger driver of acidification than previously thought. The fact that this study took place in the U.K. is itself irrelevant. The chemical interactions of HCl in water are the same the world over and sensitive ecosystems exist in the U.S. as well as in Europe as illustrated in the ecological risk assessment [301] for NO_X and SO_X. Furthermore, the commenter is factually incorrect that EPA is justifying that it is appropriate and necessary to regulate HAP emissions from EGUs based on this one study. The EPA agrees with the commenter that Hg exposure in wildlife is responsible for various adverse health effects in many species across the U.S. and recognizes that research is ongoing in this area. As discussed in the preamble to the proposed rule, the EPA agrees that there are potential environmental risks from exposures of ecosystems through Hg and non-Hg HAP deposition. The EPA cited relevant articles from the special edition of *Ecotoxicology* [302] mentioned by the commenter in the ecosystem effects section on Chapter 5 of the RIA for this rule, which is available in the docket.

G. EPA Affirms the Finding That It Is Appropriate and Necessary to Regulate EGUs To Address Public Health and Environmental Hazards Associated With Emissions of Hg and Non-Hg HAP From EGUs

In response to peer reviews of both the Hg and non-Hg HAP risk analyses, and taking into account public comments, the EPA conducted revised analyses of the risks associated with emissions of Hg and non-Hg HAP from U.S. EGUs. These revised analyses demonstrated that the risk results reported in the preamble to the proposed rule are robust to revisions in response to the peer reviews and public comments.

Specifically, the revised Hg Risk TSD shows that up to 29 percent of modeled watersheds have populations potentially at-risk from exposure to Hg from U.S. EGUs.[303] This 29 percent of watersheds with populations potentially at-risk includes up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD, and up to 24 percent of modeled watersheds where total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. Each of these results independently supports our conclusion that U.S. EGUs pose hazards to public health.

In the preamble to the proposed rule and in the 2000 finding, the EPA explained at length the serious nature of the health effects associated with Hg exposures, and the persistent nature of Hg in the environment. Congress specifically recognized the significant impacts of persistent bioaccumulative pollutants, like Hg, when it enacted section 112(c)(6), which requires the EPA to subject source categories listed pursuant to that section to MACT standards. Congress also required certain studies be conducted under CAA section 112(n) regarding the health effects of Hg. The EPA interprets CAA section 112(n)(1), with regard to Hg, as intended to protect the public, including sensitive populations, against exposures to Hg from EGUs that would exceed the level determined by the EPA to be without appreciable risk, *e.g.,* exposures that are above the RfD for methylmercury (MeHg), or would contribute additional risk in areas where Hg exposures exceed the RfD due to contributions from all sources of Hg. Our recent technical analyses show that 98 percent of the watersheds for which we had fish tissue data have total Hg deposition such that potential exposures exceed the MeHg RfD, above which there is an increased risk of adverse effects on human health. In these watersheds, any reductions in exposures to Hg will reduce risk, and thus the incremental contribution to Hg exposure from any individual source or group of sources, such as EGUs, may reasonably be anticipated to cause additional risk.

As we have explained, in calculating the estimates described above, the EPA has used peer-reviewed methods, and focused on populations likely to be at higher risk of exposure to Hg from U.S. EGUs, *e.g.,* female subsistence fishing populations consuming at the 99th percentile fish consumption rate. The EPA did not, however, use the most conservative assumptions that would lead to upper bound risk estimates. As discussed above and in the revised Hg Risk TSD, we did not use the highest fish tissue cooking loss adjustment factor that was reported in the literature, which, had we done so, would have increased the estimates of Hg exposure substantially. Thus, we believe our analysis could understate risk to the most exposed individual, noting that we have focused on the 99th percentile consumption rate in our estimates.

Further, we were able to assess potential Hg exposures in only a small subset of generally representative watersheds in the U.S. because our analysis was necessarily premised on those water bodies for which we had fish tissue Hg samples. Specifically, we analyzed 3,141 of the approximately 88,000 watersheds in the United States. This limited set of watersheds excludes several of the watersheds with the highest U.S. EGU attributable deposition, and may also not have included watersheds with the highest sensitivity to Hg deposition, *e.g.,* the highest methylation rates (see above). Nevertheless, our analysis of the subset of watersheds we examined demonstrates that almost one third of the watersheds are estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the MeHg RfD. The SAB

[298] Id.

[299] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Risk and Exposure Assessment for Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur (Final).* EPA–452/R–09–008a. Office of Air Quality Planning and Standards, Research Triangle Park, NC. September. Available on the Internet at *http://www.epa.gov/ttn/naaqs/standards/no2so2sec/data/NOxSOxREASep2009MainContent.pdf.*

[300] U.S. Environmental Protection Agency (U.S. EPA). 2011d. *Policy Assessment for the Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur.* EPA–452/R–11–005a. Office of Air Quality Planning and Standards, Research Triangle Park, NC. February. Available on the Internet at *http://www.epa.gov/ttnnaaqs/standards/no2so2sec/data/20110204pamain.pdf.*

[301] U.S. EPA, 2009.

[302] *Ecotoxicology* 17:83–91, 2008.

[303] This corresponds to 28 percent of modeled watersheds with populations potentially at-risk in the analysis reported in the preamble to the proposed rule.

confirmed that the subset of watersheds we examined is sufficient.

Considering these points and the information on Hg in the record, the EPA believes that 10 percent of watersheds with populations at risk due to U.S. EGU emissions alone is unacceptable, as is 24 percent of watersheds with populations at risk due to U.S. EGU contributions in conjunction with total deposition from other sources. Taking into account the percentage of watersheds at risk, and the potential for even higher percentages to be at risk using more conservative risk assumptions and a more complete coverage of high U.S. EGU Hg deposition watersheds, the EPA concludes that Hg emissions from U.S. EGUs pose a hazard to public health.

Given these findings, and considering that (1) the revised risk analysis showed the percent of modeled watersheds with populations potentially at-risk increased from 28 to 29 percent, and (2) the revised analysis includes 36 percent more watersheds, which significantly expands the coverage in several states, we conclude that the finding that emissions of Hg from U.S. EGUs pose a hazard to public health is confirmed by the national-scale revised Hg Risk TSD. As a result, we conclude that it remains appropriate to regulate Hg emissions from U.S. EGUs because those Hg emissions pose a hazard to public health.

With regards to the revised non-Hg inhalation case studies, the highest estimated individual lifetime cancer risk for the one case study facility (out of 16) with oil-fired EGUs is estimated to be 20 in a million, driven by Ni emissions. For the facilities with coal-fired EGUs, there were five (out of 16) with maximum individual cancer risks greater than one in a million (the highest was five in a million), four of which were driven by emissions of Cr(VI), and one of which was driven by emissions of Ni. Therefore, a total of six facilities exceed the criterion for EGUs to be regulated under CAA section 112. There were also two facilities with coal-fired EGUs with maximum individual cancer risks at one in a million. In the preamble to the proposed rule, we reported that the maximum individual lifetime cancer risk for the one facility with oil-fired EGUs was estimated to be 10 in a million, and that there were 3 coal-fired EGU facilities with maximum individual cancer risks greater than 1 in a million (the highest was 8 in a million), and 1 coal-fired EGU facility with maximum individual cancer risks equal to 1 in a million. Given that (1) the lifetime cancer risk for the oil-fired EGU facility has increased from 10 to 20 in a million, (2) the number of coal-fired EGU facilities with cancer risks greater than 1 in a million has increased from 3 to 5, and (3) the highest risk coal-fired facility still has cancer risks of 5 in a million, which is above the 1 in a million benchmark, we conclude that the finding that emissions of non-Hg HAP from U.S. EGUs pose a hazard to public health is confirmed by the revised non-Hg risk inhalation case studies.

Moreover, some HAP emissions from U.S. EGUs contribute to adverse ecosystem effects. While we did not do new analyses on these topics, we reiterate that (1) Hg emissions from U.S. EGUs pose a hazard to the environment, contributing to adverse impacts on fish-eating birds and mammals, (2) Hg is a persistent bioaccumulative environmental contaminant, and as a result, failing to control Hg emissions from U.S. EGU sources will result in long-term environmental loadings of Hg, above and beyond those loadings caused by immediate deposition of Hg within the U.S.; controlling Hg emissions from U.S. EGUs helps to reduce the potential for environmental hazard from Hg now and in the future, and (4) it is appropriate to regulate those HAP which are not known to cause cancer but are known to contribute to chronic non-cancer toxicity and environmental degradation, such as the acid gases. In addition, we have identified effective controls available to reduce Hg and non-Hg HAP emissions.

In summary, we confirm the findings that Hg and non-Hg HAP emissions from U.S. EGUs each pose hazards to public health and that it remains appropriate to regulate U.S. EGUs under CAA section 112 for those reasons. We also conclude that it remains appropriate to regulate EGUs under CAA section 112 because of the magnitude of Hg and non-Hg emissions and the environmental effects of Hg and some non-Hg emissions, each of which standing alone, supports the appropriate finding. The availability of controls to reduce HAP emissions from EGUs only further supports the appropriate finding.

Our revised analyses still show that in 2016 after implementation of other provisions of the CAA, HAP emissions from U.S. EGUs are reasonably anticipated to pose hazards to public health; therefore, it is necessary to regulate EGUs under CAA section 112. Moreover, HAP emissions from U.S. EGUs are expected to continue to contribute to adverse ecosystem effects. In addition, based on evaluation of the regulations required by the CAA, including the recent CSAPR, it is necessary to regulate U.S. EGUs under CAA section 112 because the only way to ensure permanent reductions in HAP emissions from U.S. EGUs and the associated risks to public health and the environment is through standards set under CAA section 112. While CSAPR is projected to achieve some Hg reductions due to co-control of Hg provided by controls put in place to achieve required reductions in SO_2 emissions, the results of the revised Hg Risk TSD indicate that an unacceptable percentage of modeled watersheds have populations potentially at-risk from U.S. EGU-attributable Hg deposition would remain after implementation of CSAPR. While we modeled slightly higher Hg emissions from U.S. EGUs (*i.e.*, 29 tons of Hg) in our risk analysis compared to the most recent estimate of 27 tons, we do not believe this 2 ton difference would substantially change our finding that Hg emissions from U.S. EGUs pose a hazard to public health or the Hg risks reported in the preamble to the proposed rule, as this represents less than a 10 percent reduction in Hg emissions. In addition, the actual reductions in Hg that will occur due to application of controls to meet the SO_2 emissions requirements of CSAPR may differ from those projected to occur, due to differences in the technologies that individual EGU sources choose to install. The only way to ensure reductions in Hg, including those modeled as resulting from the CSAPR, is to directly regulate Hg emissions under CAA section 112.

In summary, we confirm the findings that it is necessary to regulate HAP emissions from U.S. EGUs because (1) the national-scale Hg Risk TSD shows that the hazards to public health posed by Hg emissions from U.S. EGUs will not be addressed through imposition of the CAA, (2) we cannot be certain that the identified cancer risks attributable to U.S. EGUs will be addressed through imposition of the requirements of the CAA, (3) the environmental hazards posed by acidification will not be fully addressed through imposition of the CAA, (4) regulation under CAA section 112 is the only way to ensure that all HAP emissions reductions that have been achieved since 2005 remain permanent, and (5) direct control of Hg emissions affecting U.S. deposition is only possible through regulation of U.S. emissions as we are unable to control global emissions directly. All of these findings independently support a finding that it is necessary to regulate U.S. EGUs under CAA section 112.

Based on these findings, the Agency affirms its finding that it remains appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112, and maintains that the inclusion of coal- and oil-fired EGUs on the CAA section 112(c) list of source categories regulated under CAA section 112 remains valid.

IV. Denial of Delisting Petition

During the comment period on the proposed rule, UARG submitted a petition pursuant to CAA section 112(c)(9), asking the Agency to delete a portion of the EGU source category from the list of source categories to be regulated under CAA section 112. Specifically, UARG asks that EPA delist coal-fired EGUs from the CAA section 112(c) source category list. A copy of UARG's petition has been placed in the docket for today's rulemaking, along with the analysis conducted by EPRI that UARG uses to support its petition (hereinafter referred to as UARG's analysis). In support of its petition, UARG asserts that: (1) No coal-fired EGU or group of coal-fired EGUs will emit HAP in amounts that will cause a lifetime cancer risk greater than one in one million; and (2) no coal-fired EGU or group of coal-fired EGUs will emit non-carcinogenic HAP in amounts that will exceed a level which is adequate to protect public health with an ample margin of safety or cause adverse environmental effects. We disagree with UARG's assertions and for the reasons set forth below are denying UARG's petition to delist coal-fired EGUs from the section 112(c) source category list.

A. Requirements of CAA Section 112(c)(9)

CAA section 112(c)(9)(B) provides that ''[t]he Administrator may delete any source category'' from the section 112(c) source category list if the Agency determines that: (i) For HAP that may cause cancer in humans, ''no source in the category (or group of sources in the case of area sources) emits such hazardous air pollutants in quantities which may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source (or group of sources in the case of area sources)''; and (ii) for HAP that may result in human health effects other than cancer or adverse environmental effects, ''a determination that emissions from no source in the category or subcategory concerned (or group of sources in the case of area sources) exceed a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source.''

The EPA has the discretion to delete a source category under CAA section 112(c)(9)(B), but only if EPA concludes that the relevant requirements of CAA section 112(c)(9)(B) have been met. HAP emissions from EGUs present both cancer risks, which implicate the requirements of CAA section 112(c)(9)(B)(i), and non-cancer human health effects or adverse environmental effects, which implicate the requirements of CAA section 112(c)(9)(B)(ii). As such, UARG bears the burden of demonstrating that the requirements of *both* clauses are met.

B. Rationale for Denying UARG's Delisting Petition

The EPA is denying UARG's petition to delist EGUs from the CAA section 112(c) source category list. UARG improperly seeks to delist a portion of a CAA section 112(c) listed source category that emits carcinogens, which is contrary to the plain language of CAA section 112(c)(9). Even setting aside this fundamental defect, UARG has failed to meet the requirements of CAA section 112(c)(9)(B).

1. UARG's Attempt to Delist a Portion of a Listed Source Category Conflicts With D.C. Circuit Precedent

In December 2000, the EPA listed coal- and oil-fired EGUs as a single source category. UARG asks the Agency to delist a portion of that listed source category: Coal-fired EGUs. UARG's request conflicts, however, with D.C. Circuit precedent, which provides that for categories, like EGUs, that pose cancer risks, the EPA may not delist a portion of a source category. *NRDC* v. *U.S. EPA*, 489 F.3d 1364 (D.C. Cir. 2007). Specifically, in *NRDC*, the D.C. Circuit held that the Agency's attempt to delist a ''low-risk'' subcategory was ''contrary to the plain language of the statute,'' and that the statute only authorized the agency to remove source categories pursuant to section 112(c)(9). *Id. at 1373* (''Because EPA's interpretation of Section 112(c)(9) as allowing it to exempt the risk-based subcategory is contrary to the plain language of the statute, the EPA's interpretation fails at Chevron step one.'').

UARG's request is indistinguishable from the situation before the court in *NRDC.* UARG does not seek to delist coal- and oil-fired EGUs, which is the source category that EPA listed, but rather a portion of that category. UARG also does not dispute that coal-fired EGUs emit carcinogenic HAP. Because UARG's request to delist is contrary to the plain language of CAA section 112(c)(9)(B) and *NRDC*, we are denying the delisting petition.

2. Even Assuming, for the Sake of Argument, That EPA Could Delist a Portion of a Source Category, UARG has Failed to Meet the Requirements of CAA Section 112(c)(9)

Even assuming, for the sake of argument, that EPA could delist a portion of a source category that emits carcinogens, which it cannot, UARG has failed to demonstrate that the requirements for delisting in CAA section 112(c)(9)(i) and (ii) have been met. UARG contends that it used EPA's models and approaches, as well as the most recent data. We have carefully reviewed UARG's analyses, however, and found certain flaws that we believe bias their risk results low. Specifically, we identified flaws in emissions estimation. UARG developed estimates for all EGU facilities using data which pre-date the 2010 ICR emissions measurement data that EPA obtained to support this rule. UARG also relied upon an emissions equation developed by EPRI and DOE to develop its metal emissions estimates. With regard to that approach, the EPA analysis of the ICR data has found that the regression approach is not a good predictor of actual EGU emissions. Furthermore, we found fault with their use of the geometric mean and their outlier analysis for computing emission factors. The EPA analysis has found that the geometric mean approach underpredicts actual emissions by an average of more than seventy percent. This had an especially large impact on the arsenic, chromium, and nickel emissions estimates. These and other issues are explained in further detail in the response to comments document. As a result, we believe the resulting risk estimates in UARG's analysis are biased low. In addition, we note that there are dispersion model refinements that are not included in the UARG analyses, but were included in EPA's analysis. For example, for the dispersion modeling of the 16 non-Hg case studies, the EPA considered building downwash and used time-varying emissions, neither of which were used in UARG's analysis. These factors could also bias the UARG risk estimates low.

However, even taking UARG's analysis at face value and accepting, for arguments' sake, their assumptions and emissions estimates, UARG's own data supports denial of the petition because UARG itself identifies a maximum individual cancer risk exceeding 1 in a million, which is the statutory threshold in CAA section 112(c)(9)(B)(i). Specifically, UARG's multi-pathway model plant ingestion risk analysis concluded that adult anglers would face cancer risks of 4 in a million. For this reason alone, the petition should be denied.

UARG dismisses the 4 in a million cancer result, arguing that the refined model plant multipathway risk assessment that it conducted is ''overly conservative.'' UARG conducted its multi-pathway risk analysis to evaluate the risks associated with ingesting persistent and bioaccumulative HAP which are emitted into the atmosphere and subsequently deposit into the environment and bioaccumulate in animals which are eventually consumed as food. Instead of conducting this multipathway analysis for each EGU facility, UARG instead analyzed multi-pathway risks by evaluating a single model plant. Nothing in the record indicates, however, that UARG's model plant represents the worst-case scenario for cancer human health risks from any EGU. Indeed, although UARG claims in its petition that the site selected for its case study is ''likely as close to a worst-case scenario as is possible given the numerous variables associated with ingestion pathway risks'' (UARG petition at 12), the supporting documentation for that case study specifically acknowledges that its fictional model plant scenario ''is not intended to represent the risk due to emissions from an actual plant or the highest level of risk that could be associated with a coal-fired power plant at any location'' (EPRI at 1). The statute requires that no source in the category may cause a lifetime cancer risk greater than one in one million to the most exposed individual, and UARG has failed to make this showing. UARG has neither modeled multi-pathway risks for a worst-case model facility, nor evaluated the multipathway risks associated with each individual EGU facility. Accordingly, UARG has not made the demonstration required by CAA section 112(c)(9)(B)(i). But, even focusing on the multi-pathway risk analysis that UARG did conduct, which admittedly does not represent a worst-case facility, UARG's analysis still shows cancer risks greater than one in a million. Accordingly, UARG's petition must be denied.

Although it is not necessary to reach the requirements of CAA section 112(c)(9)(B)(ii) that address non-cancer human health risks, we note that UARG has also failed to show that ''emissions from no source in the category * * * exceed a level which is adequate to protect public health with an ample margin of safety.'' Again, even accepting, for argument's sake, the conclusions in UARG's analysis, UARG only evaluated the non-cancer *inhalation* risks associated with each EGU facility. It did not conduct a similar analysis to assess multipathway risks for each EGU facility. Instead, it conducted a model plant analysis and admits that such model plant does not represent the worst-case scenario for noncancer human health risks from any EGU. Thus, the analysis fails to fully characterize noncancer multipathway risks for the source category, and UARG's petition must be denied on this basis as well.

Finally, UARG failed to meet its burden of showing that ''no adverse environmental effect will result from emissions from any source'' pursuant to CAA section 112(c)(9)(B)(ii). UARG analyzed environmental effects only in conjunction with its model plant. Because UARG's model plant does not represent the worst-case scenario for environmental effects, UARG's analysis falls short and fails to characterize fully the potential environmental impacts, and UARG's petition must be denied.

For all of these reasons, the EPA denies UARG's petition to delist coal-fired EGUs from the CAA section 112(c) source category list.

C. EPA's Technical Analyses for the Appropriate and Necessary Finding Provide Further Support for the Conclusion That Coal-Fired EGUs Should Remain a Listed Source Category

The EPA reasonably concluded in December 2000, based on the information available to the Agency at that time, that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under CAA section 112(d). As discussed in section III above, the EPA conducted additional, extensive technical analyses based on recent data that confirm it remains appropriate and necessary to regulate HAP from coal- and oil-fired EGUs, because such EGUs continue to pose hazards to public health. HAP emissions from coal- and oil-fired EGUs also continue to cause adverse environmental effects. UARG advances several arguments, challenging the analyses the Agency completed in support of the proposed rule. We address those arguments in section III above. The Agency's analyses supporting the appropriate and necessary finding confirm that EGUs cannot be delisted pursuant to CAA section 112(c)(9).

Specifically, as explained further in section III above, the EPA analyzed non-Hg inhalation risks from 16 EGU facility case studies, including both coal- and oil-fired EGUs, as part of its technical analyses supporting the appropriate and necessary finding. That analysis demonstrates that there are 6 EGU facilities (of the 16 that we analyzed) with cancer risks exceeding one in one million. These cancer risk levels exceed the delisting criteria set forth in CAA section 112(c)(9)(B)(i), and confirm that EGUs must remain a listed source category. As explained above, some commenters assert that EPA's analysis of non-Hg inhalation risks from EGUs conducted in support of the proposal for this rulemaking overstated emissions from, and risks associated with, EGUs. These commenters argue that the analysis supporting UARG's petition more appropriately assesses EGU risk. The EPA disagrees with these comments and addresses these comments in section III above.

Significantly, the EPA based its analysis of 16 case study EGUs directly on the 2010 emissions test data from EGUs obtained through the ICR. The EPA's 16 case study analysis used emissions data either taken directly from the 2010 emissions test data, or derived using emissions factors based on the 2010 data for similar EGU units. The EPA also included dispersion model refinements in its final case studies, as noted above. Further, the EPA re-analyzed the 16 case studies that we conducted for the proposal and revised those analyses consistent with new non-Hg HAP emissions data and corrected stack parameters provided by commenters (including UARG) during the comment period on the proposed rule. The EPA received revised information concerning emissions tests, stack heights and stack diameters for some of the case study EGU facilities. The EPA incorporated all of these corrections into our analysis and then re-analyzed the risks for the 16 case study facilities. When completed, the EPA determined that the corrections incorporated into the reanalysis had little effect on the overall results. In the final rule, the EPA concludes that the maximum individual inhalation cancer risks for 6 out of the 16 case study EGU facilities are greater than 1 in a million. These cancer risk levels confirm that EGUs do not satisfy the delisting criterion of CAA section 112(c)(9)(B)(i) and thus should remain a listed source category.

The EPA's national-scale Hg Risk TSD supporting the appropriate and necessary finding also confirm that Hg emissions from coal- and oil-fired US EGUs are reasonably anticipated to pose a hazard to public health. As discussed in section III above, the EPA interprets CAA section 112(n)(1), with regard to mercury, as intended to protect the public, including sensitive populations, against exposures to Hg from EGUs that would exceed the level determined by EPA to be without appreciable risk, e.g., exposures that are above the RfD for methylmercury (MeHg), or would contribute additional risk in areas where Hg exposures exceed the RfD due to contributions from all sources of Hg.

In order to determine whether EGU Hg emissions pose a hazard to public health, the EPA conducted a national-scale Hg Risk TSD focused on populations with high levels of self-caught freshwater fish consumption. The results of the Hg Risk TSD show that 98 percent of modeled watersheds have total exposures to MeHg that exceed the MeHg RfD, above which there is an increased risk of adverse effects on human health. In these watersheds, any reductions in exposures to Hg will reduce risk, and thus the incremental contribution to Hg exposure from any individual source or group of sources, such as EGUs, may reasonably be anticipated to cause additional risk. The Hg Risk TSD focused on those watersheds that either exceeded the RfD based on U.S. EGU attributable deposition alone, without considering other sources of deposition, or watersheds that exceed the RfD due to total Hg deposition and to which U.S. EGUs contributed at least 5 percent of the Hg deposition. The results of that analysis show that up to 29 percent of the modeled watersheds have populations that are potentially at-risk from exposure to Hg from U.S. EGUs, including up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD, and up to 24 percent of modeled watersheds where total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. This approach to assessing national risks from Hg deposition from EGUs was supported by the independent peer review conducted by the Science Advisory Board, as discussed fully in section III.

Finally, as discussed in section III, based on this assessment, the EPA has confirmed that Hg emitted from U.S. EGUs pose a hazard to public health and it is appropriate to regulate U.S. EGUs under CAA section 112. This determination and the confirmatory assessments support our conclusion that UARG's delisting petition must be denied.

UARG attempts to dismiss the results of EPA's national-scale Hg Risk TSD, arguing that EPA cannot consider the risks posed by EGUs in conjunction with any other risks, including those from other source categories. Nothing in CAA section 112(c)(9), however, provides that the Agency cannot consider background or emissions due to other sources. CAA section 112(c)(9)(B)(ii) provides that ''no source in the category or subcategory concerned (or group of sources in the case of area sources) exceed a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source.'' This language could be read to provide that the Agency consider only the risks associated with the source category at issue, and ignore how those risks fit with real-world exposures.[304] However, the language could also be read to provide that the Agency consider the cumulative effect of HAP emissions from the individual sources in the category in conjunction with the HAP emissions from other sources. The latter is a reasonable interpretation, especially when considering how the public is exposed to HAP emissions. Considering the individual sources in a source category in isolation treats the sources as if they exist in a vacuum, which does not mirror reality. Such an approach is particularly problematic for environmentally persistent HAP that bio-accumulate in the food chain, such as mercury.[305]

Here, the record demonstrates that 98 percent of the watersheds EPA modeled have total exposures to MeHg that exceed the MeHg RfD, above which there is increased risk of adverse effects on human health, especially on the developing nervous systems of children during gestation. EGUs remain one of the largest unregulated sources of Hg emissions, and those emissions continue to contribute to Hg exposures and risk. UARG seeks to ignore the fact that exposures above the RfD exist in almost every watershed we modeled, and instead focuses on the contribution provided solely by EGUs. The EPA did as UARG asked and found that up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD. Thus, even focusing on EGU emissions in a vacuum, which we do not believe is appropriate or required under CAA section 112(c)(9), we still found that up to 10 percent of the watersheds exceed the RfD due to EGU emissions even before taking into account the numerous other sources of Hg deposition, and we believe this to be an unacceptable percentage of watersheds above the RfD. Due to the persistent, bioacccumulative nature of Hg, among other factors, we believe it is appropriate to consider the combined impact of Hg emissions from EGUs and other sources of Hg. Thus, we also considered the 24 percent of modeled watersheds where, even though U.S. EGU emissions alone are not enough to cause exposures that exceed the RfD, those emissions contribute at least 5 percent of total exposures to MeHg that exceed the RfD. The combined total of 29 percent of modeled watersheds where U.S. EGUs cause or contribute to MeHg exposures above the RfD is clearly unacceptable and thus the UARG petition to delist must be denied.

Thus, the technical analyses the Agency conducted in support of the appropriate and necessary finding confirm that EGUs should remain a listed source category.

V. Summary of This Final NESHAP

This section summarizes the requirements of the final EGU NESHAP. Section VI below summarizes the significant changes to this final rule following proposal.

A. What is the source category regulated by this final rule?

This final rule affects coal- and oil-fired EGUs.

B. What is the affected source?

An existing affected source under this final rule is the collection of coal- or oil-fired EGUs in a subcategory within a single contiguous area and under common control. A new affected source is each coal- or oil-fired EGU for which construction or reconstruction began after May 3, 2011.

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[304] The same is true with respect to section 112(c)(9)(B)(i).

[305] In a prior rulemaking, EPA stated that the language in section 112(c)(9)(B)(ii) ''does not direct EPA to extend its analysis to either emissions from other sources in other categories or subcategories or to non-attributable background concentrations.'' 71 FR 8347 (Feb. 16, 2006). The preamble to that rule repeatedly states that the ''focus'' of the delisting determination in that rule was on emissions from sources in the category under review. *See* 71 FR 8346–47. The preamble went on to compare section 112(c)(9)(B) to section 112(f)(2)(A) in a way that suggested that EPA can consider risks presented by sources other than the subject source category under section 112(f)(2), but not under section 112(c)(9). We do not believe the language of section 112(c)(9) compels any different treatment. The section 112(f) analysis occurs after a source category has already complied with section 112(d) standards, whereas, potential delistings under section 112(c)(9) may involve source categories unregulated by section 112. A delisting decision is significant in that the category that is delisted will no longer be subject to HAP regulation under the Act. It is difficult to justify why we would examine risks from other sources under section 112(f), but not under section 112(c)(9), where Congress established such a specific test for delisting.

CAA section 112(a)(8) defines an EGU as: a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit.

If an EGU burns coal (either as a primary fuel or as a supplementary fuel) or any combination of coal with another fuel (except for solid waste as noted below) where the coal accounts for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date, the unit is considered to be coal-fired under this final rule.

If a unit is not a coal-fired unit and burns only oil or burns oil in combination with a fuel other than coal (except solid waste as noted below) where the oil accounts for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date, the unit is considered to be oil-fired under this final rule.

As noted below, the EPA is finalizing in this rule a definition to determine whether the combustion unit is ‘‘fossil fuel fired’’ such that it is considered an EGU as defined in CAA section 112(a)(8) and, thus, potentially subject to this final rule. In addition, using the construct of the definition of ‘‘oil-fired’’ from the ARP, we are finalizing in this rule a requirement that the unit fire coal or oil (or natural gas), or any combination thereof, for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year to be considered a ‘‘fossil fuel-fired’’ EGU as defined in CAA section 112(a)(8). However, if a new or existing EGU is not coal- or oil-fired, and the unit burns natural gas exclusively or burns natural gas in combination with another fuel where the natural gas constitutes 10 percent or more of the average annual heat input during any 3 calendar years or 15 percent or more of the annual heat input during any 1 calendar year, the unit is considered to be natural gas-fired EGU and not subject to this final rule. As discussed later, we believe that this definition will address those situations where an EGU co-fires limited amounts of either coal or oil with natural gas or other non-fossil fuels (e.g., biomass).

If an EGU combusts solid waste, standards issued pursuant to CAA section 129 apply to that EGU, rather than this final rule.

C. What are the pollutants regulated by this final rule?

For coal-fired EGUs, this final rule regulates HCl as a surrogate for acid gas HAP, with an alternate of SO_2 as a surrogate for acid gas HAP for coal-fired EGUs with FGD systems installed and operational; filterable PM as a surrogate for non-mercury HAP metals, with total non-mercury HAP metals and individual non-mercury HAP metals as alternative equivalent standards; Hg; and organic HAP. For oil-fired EGUs, this final rule regulates HCl and HF; filterable PM as a surrogate for total HAP metals, with individual HAP metals as alternative equivalent standards; and organic HAP.

D. What emission limits and work practice standards must I meet and what are the subcategories in the final rule?

We are finalizing the emission limitations presented in Tables 3 and 4 of this preamble. Within the two major subcategories of ‘‘coal’’ and ‘‘oil,’’ emission limitations were developed for new and existing sources for seven subcategories, two for coal-fired EGUs, one for IGCC EGUs burning synthetic gas derived from coal- and/or solid oil-derived fuel, one for solid oil-derived fuel-fired EGUs, and four for liquid oil-fired EGUs, as described in more detail below. The limited-use liquid oil-fired subcategory, discussed elsewhere in this preamble, is not presented in Table 3 because only work practice standards apply to this subcategory.

TABLE 3—EMISSION LIMITATIONS FOR COAL-FIRED AND SOLID OIL-DERIVED FUEL-FIRED EGUS

Subcategory	Filterable particulate matter	Hydrogen chloride	Mercury
Existing—Unit not low rank virgin coal	3.0E–2 lb/MMBtu. (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu. (2.0E–2 lb/MWh)	1.2E0 lb/TBtu. (1.3E–2 lb/GWh).
Existing—Unit designed low rank virgin coal	3.0E–2 lb/MMBtu. (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu. (2.0E–2 lb/MWh)	1.1E+1 lb/TBtu. (1.2E–1 lb/GWh). 4.0E0 lb/TBtu [a]. (4.0E–2 lb/GWh [a]).
Existing—IGCC	4.0E–2 lb/MMBtu. (4.0E–1 lb/MWh)	5.0E–4 lb/MMBtu. (5.0E–3 lb/MWh)	2.5E0 lb/TBtu. (3.0E–2 lb/GWh).
Existing—Solid oil-derived	8.0E–3 lb/MMBtu. (9.0E–2 lb/MWh)	5.0E–3 lb/MMBtu. (8.0E–2 lb/MWh)	2.0E–1 lb/TBtu. (2.0E–3 lb/GWh).
New—Unit not low rank virgin coal	7.0E–3 lb/MWh	4.0E–4 lb/MWh	2.0E–4 lb/GWh.
New—Unit designed for low rank virgin coal	7.0E–3 lb/MWh	4.0E–4 lb/MWh	4.0E–2 lb/GWh.
New—IGCC	7.0E–2 lb/MWh [b] 9.0E–2 lb/MWh [c]	2.0E–3 lb/MWh [d]	3.0E–3 lb/GWh [e].
New—Solid oil-derived	2.0E–2 lb/MWh	4.0E–4 lb/MWh	2.0E–3 lb/GWh.

Note: lb/MMBtu = pounds pollutant per million British thermal units fuel input.
lb/TBtu = pounds pollutant per trillion British thermal units fuel input.
lb/MWh = pounds pollutant per megawatt-hour electric output (gross).
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).
[a] Beyond-the-floor limit as discussed elsewhere.
[b] Duct burners on syngas; based on permit levels in comments received.

[c] Duct burners on natural gas; based on permit levels in comments received.
[d] Based on best-performing similar source.
[e] Based on permit levels in comments received.

TABLE 4—EMISSION LIMITATIONS FOR LIQUID OIL-FIRED EGUS

Subcategory	Filterable particulate matter	Hydrogen chloride	Hydrogen fluoride
Existing—Liquid oil—continental	3.0E–2 lb/MMBtu (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu (1.0E–2 lb/MWh)	4.0E–4 lb/MMBtu. (4.0E–3 lb/MWh).
Existing—Liquid oil—non-continental	3.0E–2 lb/MMBtu (3.0E–1 lb/MWh)	2.0E–4 lb/MMBtu (2.0E–3 lb/MWh)	6.0E–5 lb/MMBtu. (5.0E–4 lb/MWh).
New—Liquid oil—continental	7.0E–2 lb/MWh	4.0E–4 lb/MWh	4.0E–4 lb/MWh.
New—Liquid oil—non-continental	2.0E–1 lb/MWh	2.0E–3 lb/MWh	5.0E–4 lb/MWh.

We are also finalizing alternate equivalent emission standards (for certain subcategories) to the final surrogate standards in three areas: SO_2 (for HCl), individual non-mercury metals and total non-mercury metals (for filterable PM) from coal- and solid oil-derived fuel-fired EGUs, and individual and total metals (for filterable PM) from oil-fired EGUs. The final alternate emission limitations are provided in Tables 5 and 6 of this preamble.

TABLE 5—ALTERNATE EMISSION LIMITATIONS FOR EXISTING COAL- AND OIL-FIRED EGUS

Subcategory/Pollutant	Coal-fired EGUs	IGCC	Liquid oil, continental	Liquid oil, non-continental	Solid oil-derived
SO_2	2.0E–1 lb/MMBtu (1.5E0 lb/MWh)	NA	NA	NA	3.0E–1 lb/MMBtu. (2.0E0 lb/MWh).
Total non-mercury metals	5.0E–5 lb/MMBtu (5.0E–1 lb/GWh)	6.0E–5 lb/MMBtu (5.0E–1 lb/GWh)	8.0E–4 lb/MMBtu (8.0E–3 lb/MWh) [a]	6.0E–4 lb/MMBtu (7.0E–3 lb.MWh) [a]	4.0E–5 lb/MMBtu. (6.0E–1 lb/GWh).
Antimony, Sb	8.0E–1 lb/TBtu (8.0E–3 lb/GWh)	1.4E0 lb/TBtu (2.0E–2 lb/GWh)	1.3E+1 lb/TBtu (2.0E–1 lb/GWh)	2.2E0 lb/TBtu (2.0E–2 lb/GWh)	8.0E–1 lb/TBtu. (8.0E–3 lb/GWh).
Arsenic, As	1.1E0 lb/TBtu (2.0E–2 lb/GWh)	1.5E0 lb/TBtu (2.0E–2 lb/GWh)	2.8E0 lb/TBtu (3.0E–2 lb/GWh)	4.3E0 lb/TBtu (8.0E–2 lb/GWh)	3.0E–1 lb/TBtu. (5.0E–3 lb/GWh).
Beryllium, Be	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	1.0E–1 lb/TBtu (1.0E–3 lb/GWh)	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	6.0E–1 lb/TBtu (3.0E–3 lb/GWh)	6.0E–2 lb/TBtu. (6.0E–4 lb/GWh).
Cadmium, Cd	3.0E–1 lb/TBtu (3.0E–3 lb/GWh)	1.5E–1 lb/TBtu (2.0E–3 lb/GWh)	3.0E–1 lb/TBtu 2.0E–3 lb/GWh)	3.0E–1 lb/TBtu (3.0E–3 lb/GWh)	3.0E–1 lb/TBtu. (4.0E–3 lb/GWh).
Chromium, Cr	2.8E0 lb/TBtu (3.0E–2 lb/GWh)	2.9E0 lb/TBtu (3.0E–2 lb/GWh)	5.5E0 lb/TBtu (6.0E–2 lb/GWh)	3.1E+1 lb/TBtu (3.0E–1 lb/GWh)	8.0E–1 lb/TBtu. (2.0E–2 lb/GWh).
Cobalt, Co	8.0E–1 lb/TBtu (8.0E–3 lb/GWh)	1.2E0 lb/TBtu (2.0E–2 lb/GWh)	2.1E+1 lb/TBtu (3.0E–1 lb/GWh)	1.1E+2 lb/TBtu (1.4E0 lb/GWh)	1.1E0 lb/TBtu. (2.0E–2 lb/GWh).
Lead, Pb	1.2E0 lb/TBtu (2.0E–2 lb/GWh)	1.9E+2 lb/MMBtu (1.8E0 lb/MWh)	8.1E0 lb/TBtu (8.0E–2 lb/GWh)	4.9E0 lb/TBtu (8.0E–2 lb/GWh)	8.0E–1 lb/TBtu. (2.0E–2 lb/GWh).
Manganese, Mn	4.0E0 lb/TBtu (5.0E–2 lb/GWh	2.5E0 lb/TBtu (3.0E–2 lb/GWh)	2.2E+1 lb/TBtu (3.0E–1 lb/GWh)	2.0E+1 lb/TBtu (3.0E–1 lb/GWh)	2.3E0 lb/TBtu. (4.0E–2 lb/GWh).
Mercury, Hg	NA	NA	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	4.0E–2 lb/TBtu (4.0E–4 lb/GWh).	NA.
Nickel, Ni	3.5E0 lb/TBtu (4.0E–2 lb/GWh)	6.5E0 lb/TBtu (7.0E–2 lb/GWh)	1.1E+2 lb/TBtu (1.1E0 lb/GWh)	4.7E+2 lb/TBtu (4.1E0 lb/GWh)	9.0E0 lb/TBtu. (2.0E–1 lb/GWh).
Selenium, Se	5.0E0 lb/TBtu (6.0E–2 lb/GWh)	2.2E+1 lb/TBtu (3.0E–1 lb/GWh)	3.3E0 lb/TBtu (4.0E–2 lb/GWh)	9.8E0 lb/TBtu (2.0E–1 lb/GWh)	1.2E0 lb/TBtu. (2.0E–2 lb/GWh).

NA = Not applicable.
[a] Includes Hg.

TABLE 6—ALTERNATE EMISSION LIMITATIONS FOR NEW COAL- AND OIL-FIRED EGUS

Subcategory/Pollutant	Coal-fired EGUs	IGCC [a]	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
SO_2	4.0E–1 lb/MWh	4.0E–1 lb/MWh	NA	NA	4.0E–1 lb/MWh
Total non-mercury metals	6.0E–2 lb/GWh	4.0E–1 lb/GWh	2.0E–4 lb/MWh [b]	7.0E–3 lb/MWh [b]	6.0E–1 lb/GWh
Antimony, Sb	8.0E–3 lb/GWh	2.0E–2 lb/GWh	1.0E–2	8.0E–3	8.0E–3 lb/GWh
Arsenic, As	3.0E–3 lb/GWh	2.0E–2 lb/GWh	3.0E–3	6.0E–2	3.0E–3 lb/GWh
Beryllium, Be	6.0E–4 lb/GWh	1.0E–3 lb/GWh	5.0E–4	2.0E–3	6.0E–4 lb/GWh
Cadmium, Cd	4.0E–4 lb/GWh	2.0E–3 lb/GWh	2.0E–4	2.0E–3	7.0E–4 lb/GWh
Chromium, Cr	7.0E–3 lb/GWh	4.0E–2 lb/GWh	2.0E–2	2.0E–2	6.0E–3 lb/GWh
Cobalt, Co	2.0E–3 lb/GWh	4.0E–3 lb/GWh	3.0E–2	3.0E–1	2.0E–3 lb/GWh
Lead, Pb	2.0E–3 lb/GWh	9.0E–3 lb/GWh	8.0E–3	3.0E–2	2.0E–2 lb/GWh
Mercury, Hg	NA	NA	1.0E–4	4.0E–4	2.0E–3 lb/GWh
Manganese, Mn	4.0E–3 lb/GWh	2.0E–2 lb/GWh	2.0E–2	1.0E–1	7.0E–3 lb/GWh

TABLE 6—ALTERNATE EMISSION LIMITATIONS FOR NEW COAL- AND OIL-FIRED EGUs—Continued

Subcategory/Pollutant	Coal-fired EGUs	IGCC [a]	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
Nickel, Ni	4.0E–2 lb/GWh	7.0E–2 lb/GWh	9.0E–2	4.1E0	4.0E–2 lb/GWh
Selenium, Se	6.0E–3 lb/GWh	3.0E–1 lb/GWh	2.0E–2	2.0E–2	6.0E–3 lb/GWh

NA = Not applicable.
[a] Based on best-performing similar source.
[b] Includes Hg.

As noted elsewhere in this preamble, we are finalizing a requirement to use filterable PM as a surrogate for the non-mercury metallic HAP and HCl as a surrogate for the acid gas HAP for all subcategories of coal-fired EGUs and for the solid oil derived fuel-fired EGUs. For all liquid oil-fired EGUs, we are finalizing a requirement to use filterable PM as a surrogate for the total metallic HAP, and we are finalizing HCl and HF limits.

In addition, we are finalizing alternative standards for certain HAP for some subcategories. The alternative pollutants and subcategories are as follows: (1) SO_2 as a surrogate to HCl for all subcategories with add-on FGD systems (except liquid oil-fired subcategories as there were no existing units from which to base an alternate SO_2 limit); (2) individual non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories); and (3) total non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories). These alternative standards are discussed elsewhere in this preamble.

We are finalizing a beyond-the-floor standard for Hg only for all existing coal-fired units designed for low rank virgin coal based on the use of activated carbon injection (ACI) for Hg control, as described elsewhere in this preamble. The EPA has determined that this beyond-the-floor level is achievable after considering the relevant CAA section 112(d)(2) provisions.

As noted elsewhere in this preamble, we are also finalizing a compliance assurance option that would allow you to monitor liquid oil fuel moisture to demonstrate that fuel moisture content is no greater than 1.0 percent. Provided that demonstration is made, you will not have to conduct additional testing and monitoring to demonstrate compliance with the HCl and HF emission limits for units in both liquid oil subcategories (*i.e.,* continental and non-continental).

Pursuant to CAA section 112(h), we are finalizing a work practice standard for organic HAP, including emissions of dioxins and furans, for all subcategories of EGUs. The work practice standard being finalized requires the implementation of periodic burner tune-up procedures described elsewhere in this preamble. We are finalizing work practice standards because the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods, even when long duration (around 8 hour) test runs are considered. As such, we consider it impracticable to measure emissions from these units. As discussed at proposal, we believe the inaccuracy of a majority of measurements, coupled with the extended sampling times used, allow a work practice standard under CAA section 112(h) to apply to these HAP.[306] We believe that a work practice standard will lead to a better environmental outcome than would be obtained through a requirement to measure a pollutant for which results may or may not be obtained. We believe that the work practice standard will result in actions being taken that will reduce emissions of these HAP.

In addition, as discussed below, we are creating a subcategory for limited use liquid oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input and we are establishing work practice standards applicable to such units pursuant to CAA section 112(h).

We are finalizing that new or existing EGUs are ''coal-fired'' if they combust coal more than 10 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year and meet the final definition of ''fossil fuel-fired.'' We are finalizing that an EGU is considered to be in the coal-fired ''unit designed for coal greater than or equal to 8,300 Btu/lb'' subcategory if the EGU: (1) meets the final definitions of ''fossil fuel-fired'' and ''coal-fired electric utility steam generating unit;'' and (2) is not a coal-fired EGU in the ''unit designed for low rank virgin coal'' subcategory.

We are finalizing that the EGU is considered to be in the ''unit designed for low rank virgin coal'' subcategory if the EGU: (1) meets the final definitions of ''fossil fuel-fired'' and ''coal-fired electric utility steam generating unit;'' and (2) is designed to burn and is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) and that is constructed and operates at or near the mine that produces such coal.[307]

We are finalizing that the EGU is considered to be an IGCC unit if the EGU: (1) Combusts a synthetic gas derived from gasified coal or solid oil-derived fuel (*e.g.,* petroleum coke, pet coke), (2) meets the final definition of ''fossil fuel-fired,'' and (3) is classified as an IGCC unit. We are not subcategorizing IGCC EGUs based on the source of the syngas used (e.g., coal, petroleum coke). Based on information available to the Agency, although the fuel characteristics of coal and petcoke are quite different, the syngas products from both feedstocks have similar HAP content and similar HAP emissions characteristics that can be controlled in a similar manner.[308]

We are finalizing that the EGU is considered to be in the ''Continental liquid oil-fired'' subcategory if (1) meets the final definitions of ''oil-fired electric utility steam generating unit'' and ''fossil fuel-fired;'' and (2) is located in the continental United States (U.S.).

We are finalizing that the EGU is considered to be ''Non-continental liquid oil-fired'' subcategory if (1) meets the final definitions of ''oil-fired electric utility steam generating unit'' and

[306] We would also note that the EPA, as a part of the Industrial Boiler MACT reconsideration proposal that was signed on December 2, 2011, is proposing to establish work practice standards for control of dioxins and furans from industrial boilers.

[307] ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14).

[308] U.S. Department of Energy, Wabash River Coal Gaification Repowering Project. Project Performance Summary; Clean Coal Technology Demonstration Program. DOE/FE–0448. July 2002. EPA–HQ–OAR–2009–0234–2933.

''fossil fuel-fired;'' and (2) is located outside continental U.S.

We are finalizing that the EGU is considered to be ''solid oil-derived fuel-fired'' if (1) the EGU is not a coal-fired EGU and burns solid oil-derived fuel (*e.g.,* petroleum coke, pet coke); and (2) meets the final definitions of ''oil-fired electric utility steam generating unit'' and ''fossil fuel-fired.''

We are finalizing that the EGU is considered to be a ''limited-use liquid oil-fired'' if (1) the EGU meets the final definitions of ''oil-fired electric utility steam generating unit'' and ''fossil fuel-fired;'' and (2) has an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing.

E. What are the requirements during periods of startup, shutdown, and malfunction?

As discussed below in section VI.E., for startup and shutdown, the requirements have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards in lieu of numeric emission limits. Numeric emission limits apply for all other periods for all pollutants, except organic HAP. For malfunctions, the EPA is finalizing an affirmative defense for exceedances of the numerical emission limits that are caused by malfunctions.

F. What are the testing and initial compliance requirements?

We are requiring that you, as an owner or operator of a new or existing coal- or oil-fired EGU, must conduct performance tests to demonstrate compliance with all applicable emission limits. For units using certified continuous emissions monitoring systems (CEMS) that directly measure the regulated pollutant under final 40 CFR part 63, subpart UUUUU (*e.g.,* Hg CEMS, HCl CEMS, HF CEMS, SO_2 CEMS (where an SO_2 limit applies as the alternative equivalent standard)), or sorbent trap monitoring systems, the initial performance test consists of all valid data recorded with the certified monitoring system in the first 30 boiler operating days of data collected with the certified monitoring system prior to the initial compliance demonstration date specified in § 63.10005. A source may also elect to use a PM CEMS to demonstrate compliance with the filterable PM emission limit. If this option is selected, then the same provisions as noted above for other CEMS will apply. (Note that EPA anticipates that the PM monitoring device that may most often will be used is a PM continuous parameter monitoring system (CPMS) in conjunction with an operating limit, as more fully described below.) For units and pollutants not being monitored via CEMS, the owner or operator of an affected unit must perform the initial performance testing in accordance with established EPA reference test methods or the voluntary consensus standard methods incorporated by reference. You, as the owner or operator of an affected unit, must conduct the following compliance tests where applicable:

(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, if you elect to comply with the filterable PM emission limit, you must conduct filterable PM emissions testing using EPA Method 5 from Appendix A to part 60 of chapter 40 to determine initial compliance. Alternatively, if you elect to comply with the total non-mercury HAP metals emission limit or the individual non-mercury HAP metals emissions limits, you must conduct HAP metals testing using EPA Method 29 from Appendix A to part 60 of chapter 40. Note for this rule that the filter temperature for each Method 5 or 29 emissions test must be maintained at $160° \pm 14$ °C ($320° \pm 25$ °F), and the material in Method 29 impingers must be analyzed for metals content. Whenever metals testing is performed with Method 29, you must report the front half and back half analytical fractions separately.

(2) For coal-fired, IGCC, and solid oil-derived fuel-fired units, you must use a Hg CEMS or a sorbent trap monitoring system for both initial compliance and continuous compliance using the continuous Hg monitoring provisions of Appendix A to 40 CFR part 63, subpart UUUUU, except where the low emitting EGU (LEE) requirements apply (see below). The initial performance test consists of all valid data recorded with the certified Hg monitoring system in the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005.

(3) For coal-fired and solid oil-derived fuel-fired units and new or reconstructed IGCC units that employ FGD technology and elect to meet the alternative SO_2 limit in place of the HCl limit, you need not conduct an initial stack test for HCl or SO_2. Instead, the 30 boiler operating days of data collected with the certified SO_2 CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance, and the SO_2 CEMS is used thereafter to demonstrate continuous compliance. If you instead opt to meet the HCl limit and use an HCl CEMS for compliance, you need not conduct an initial stack test for HCl. Instead, the 30 boiler operating days of data collected with the certified HCl CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance. For units not using the SO_2 or HCl CEMS options, you must conduct an initial stack test for HCl using EPA Method 26, 26A, or 320 from Appendix A to part 60 of chapter 40. You may use EPA Method 26 or 320 or ASTM Method D6348–03 (Reapproved 2010) with additional quality assurance if no entrained water droplets exist in the exhaust gas, but you must use Method 26A if entrained water droplets exist in the exhaust gas.

(4) For liquid oil-fired units, you must conduct initial performance testing as follows. If you elect to meet the filterable PM limit instead of the non-mercury metals limit (total or individual), then use Method 5 with the filter material maintained at $160° \pm 14$°C ($320° \pm 25$°F). Alternatively, you may use a PM CEMS as discussed elsewhere in this preamble. If you elect to meet either the total or individual HAP metals limit, you will use Method 29 for all non-mercury HAP metals. For Hg, conduct emissions testing using EPA Method 29 or 30B from Appendix A to part 60 of chapter 40, or ASTM Method D6784–02 (Reapproved 2008). For acid gases, conduct HCl and HF testing using EPA Method 26A, 320, or 26; or you may elect to comply by using an HCl CEMS and/or an HF CEMS; or under certain conditions you may choose to demonstrate compliance by measuring fuel moisture to demonstrate that moisture content is no greater than 1.0 percent. You must measure daily if fuel is delivered continuously or per shipment if fuel is delivered on a batch basis, or you may use a fuel moisture content certification provided by your fuel supplier. If you use a CEMS, then use the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005 to determine initial compliance.

(5) For the required performance stack tests, if you are demonstrating compliance with a heat-input based standard, you must conduct concurrent O_2 or carbon dioxide (CO_2) emission testing using EPA Method 3A or 3B from appendix A to part 60 of chapter 40 or ANSI/ASME PTC 19.10–1981 and then use an appropriate equation, selected from among Equations 19–1

through 19–9 in EPA Method 19 from appendix A to part 60 of chapter 40, to convert measured pollutant concentrations to lb/MMBtu values. Multiply the lb/MMBtu value by one million to get the lb/TBtu value (where applicable). If you choose to meet an electrical output-based emissions limit, you must also collect concurrent stack gas flow rate and electrical production data.

(6) For an existing unit that you believe will qualify as LEE for Hg, you must conduct an initial Method 30B test over 30 days and follow the calculation procedures in the final rule to document a potential to emit less than 10 percent of the applicable Hg emissions limit or less than 29 pounds of Hg per year. If your unit qualifies as a LEE for Hg, you must conduct subsequent performance tests on an annual basis to demonstrate that the unit continues to qualify. For all other pollutants, you must conduct the initial compliance test, and then all other required tests over a 3-year period, and in all such tests, your emission results must be less than 50 percent of the applicable emission limit. If you qualify as a LEE on that basis, you must conduct subsequent performance tests every 3 years to demonstrate that the unit continues to qualify.

(7) You may use results from tests conducted no earlier than 12 months before the compliance date of this rule as the initial performance test for an applicable pollutant, provided that:

a. You certify and keep records demonstrating that no significant changes have occurred,

b. Tests were conducted using methods allowed in this rule in accordance with § 63.10007 and Table 5,

c. You have records of all parameters needed to convert results to units of the standard for the entire period, and

d. For a CEMS-based performance test, you have all the required data for the entire 30-boiler operating day rolling average period.

Operating Limit for PM CEMS

Under the final rule, you may elect to comply continuously with an operating limit, established during the initial performance test, to demonstrate continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. You will use a PM CPMS to monitor compliance with the operating limit. The PM CPMS operating principle must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal. Meeting the operating limit serves as your demonstration of continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. As mentioned earlier, if you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals. As noted below, when you use this operating limit, you can reduce stack testing frequency to demonstrate ongoing compliance. You may also opt to install and operate a PM CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively. If you elect to use this option, then the requirements for quarterly testing with Method 5, or annual testing and use of a PM CPMS, are no longer applicable.

Dioxins/Furans and Non-Dioxin/Furan Organic HAP

For dioxins and furans and non-dioxin/furan organic HAP, you must submit documentation that you have conducted a combustion process tune-up, a thorough equipment inspection, and an optimization to minimize generation of CO and NO_X, all meeting the requirements of this final rule. The work practice standard involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO_X data and may use portable analyzers (which include handheld or similar devices) to monitor and verify the results. The specific details are addressed in 40 CFR 63.10021 of the final rule.

This same work practice standard also applies in place of any emission limits for Hg, non-mercury metals HAP, acid gas HAP, dioxins and furans, and non-dioxin/furan organic HAP from a limited-use, liquid oil-fired EGU (*i.e.,* a unit that has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater). The EPA established this subcategory in response to comments and a further analysis of the units within this subcategory in the ICR database. For these units, EPA believes that the required work practice standards are appropriate and consistent with the requirement of CAA section 112(h).

G. What are the continuous compliance requirements?

To demonstrate continuous compliance with the emission limitations, the final rule includes the following requirements:

(1) *Use of CEMS.* Where a CEMS or a sorbent trap monitoring system is used for demonstrating initial compliance, you also must use the CEMS or sorbent trap monitoring system on a continuous basis to demonstrate ongoing compliance with the numerical emission limits. CEMS or sorbent trap monitoring system data are not used to determine compliance with the work practice standards applicable during periods of startup and shutdown, but sources that install a CEMS or a sorbent trap monitoring system to demonstrate compliance with the numerical emission limits must operate the system at all times, as EPA intends to evaluate the continuous monitoring data from start-up and shutdown periods as discussed below. You must calculate a rolling average for each successive 30-boiler operating day rolling average period. All valid data collected during each successive period will be used to demonstrate compliance, except for data collected during periods of startup and shutdown; during those periods, the owner or operator must meet work practice requirements instead of the numerical emission limits. There is no numerical minimum data availability required to constitute a valid 30-boiler operating day rolling average; however, you must monitor at all times that the process is in operation (including during startups and shutdowns, although emissions during these periods are not included in the 30-boiler operating day average). You must operate, maintain, and quality-assure the CEMS or sorbent trap monitoring systems in accordance with the provisions in 40 CFR 63.10010 and Appendix A and B of the final rule (for Hg, HCl, and HF CEMS), in accordance with Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60 (for PM CEMS used for direct compliance), or in accordance with 40 CFR part 75 (for SO_2 CEMS, and certain ancillary monitors such as a diluent or moisture monitor).

For each unit using HCl, HF, SO_2, PM, or Hg CEMS or a sorbent trap monitoring system for continuous compliance, you must install, certify, maintain, operate and quality-assure the additional CEMS (*e.g.,* CEMS that measure O_2 or CO_2 concentration, stack gas flow rate, and, if default moisture values are not used, moisture content) needed to convert pollutant concentrations to units of the emission standards or operating limits. Where appropriate, you must certify and quality-assure these additional CEMS according to 40 CFR part 75.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to publish a PS specific to HCl CEMS in the near future (prior to the compliance date of this rule). In the meantime, you may petition the Administrator under the procedure given in 40 CFR 63.7(f) for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

When using a sorbent trap monitoring system, you may use each pair of sorbent traps to collect Hg samples for no more than 15 boiler operating days. Under the general duty to monitor at all times, you must replace traps in a timely manner to ensure that Hg emissions are sampled continuously.

For Hg monitoring, the EPA is adding Hg monitoring provisions as Appendix A to 40 CFR part 63, subpart UUUUU, and requiring use of these provisions to document continuous compliance with the rule for coal-fired, IGCC, and solid oil derived-fired units that cannot qualify as LEEs. Appendix A consolidates all Hg monitoring provisions.

Today's rule provides two basic Hg continuous monitoring options: Hg CEMS and sorbent trap monitoring systems. Appendix A requires initial certification and periodic quality assurance (QA) testing of the Hg CEMS and sorbent trap monitoring systems. The certification tests required for the Hg CEMS are a 7-day calibration error test; a linearity check, using NIST-traceable elemental Hg standards; a 3-level system integrity check (similar to a linearity check), using NIST-traceable oxidized Hg standards; a cycle time test; and a relative accuracy test audit (RATA). Table A–1 of Appendix A summarizes the performance specifications for the required certification tests. For ongoing QA of the Hg CEMS, Appendix A requires daily calibrations, weekly single-point system integrity checks, quarterly linearity checks (or 3-level system integrity checks), and annual RATAs. Table A–2 in Appendix A summarizes these ongoing QA test requirements and the applicable performance criteria for Hg CEMS, which are consistent with those published in support of CAMR and are, thus, familiar to the industry.

For sorbent trap monitoring systems, a RATA is required for initial certification, and annual RATAs are required for ongoing QA. The performance specification for these RATAs is the same as for the RATAs of the Hg CEMS. Bias adjustment of the measured Hg concentration data is not required. For day-to-day operation of the sorbent trap system, Appendix A requires you to follow the procedures and QA/QC criteria in PS 12B in Appendix B to 40 CFR part 60. PS 12B is nearly identical to the Appendix K to 40 CFR part 75, published in support of CAMR and with which the industry is familiar. The 40 CFR part 75 concepts of:

a. Determining the due dates for certain QA tests on the basis of "QA operating quarters" and

b. Grace periods for certain QA tests apply to both Hg CEMS and sorbent trap monitoring systems. Mercury concentrations measured by Hg CEMS or sorbent trap systems are used together with hourly flow rate, diluent gas, moisture, and electrical load data, to express the Hg emissions in units of the rule, on an hourly basis (*i.e.,* lb/TBtu or lb/GWh). Section 6 of Appendix A provides the necessary equations for these unit conversions.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, Subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to promulgate a generic PS specific to HCl CEMS prior to the compliance date of this rule. In the meantime, you may petition the Administrator under the procedure given in 40 CFR 63.7(f) for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

(2) *Use of stack tests.* If you demonstrate initial compliance on the basis of a stack test, you must demonstrate continuous compliance by conducting periodic stack tests on a quarterly basis. This includes filterable PM (or non-mercury HAP metals) and HCl from coal-fired and solid oil-derived fuel-fired EGUs, and filterable PM (or HAP metals) and HCl and HF from liquid oil-fired EGUs with the following exceptions:

a. If you use a PM CPMS and associated operating limit, you may conduct the applicable Method 5 or Method 29 test once annually rather than quarterly, in which case you must re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule includes basic quality checks that the PM CPMS must meet and a requirement for you to develop and follow a site-specific monitoring plan to be approved by the delegated authority. You must demonstrate compliance with the operating limit by using all valid hourly data collected during each successive 30-boiler operating day period rolled daily. The 30-boiler operating day rolling average is calculated by all of the valid hourly average PM CPMS output values collected for the 30 boiler operating days (excluding hours of startup and shutdown; *see* section V.E. of this preamble).

b. If you combust liquid fuels and if your fuel moisture content is no greater than 1.0 percent, you may demonstrate ongoing compliance with HCl and HF emissions limits by:

i. Measuring fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis;

ii. Measuring fuel moisture content daily if your fuel arrives on a continuous basis; or

iii. Obtaining and maintaining a fuel moisture certification from your fuel supplier.

Should the moisture in your liquid fuel be more than 1.0 percent, you must

i. Conduct HCl and HF emissions testing quarterly and establish site-specific monitoring to demonstrate continued acid gas control performance between periodic tests, or

ii. Use an HCl CEMS and/or HF CEMS.

c. If your existing unit qualifies as an LEE for Hg, you must conduct another 30-day Method 30B performance test on your unit once per year to reestablish that the unit continues to qualify as a LEE for Hg. If the results of the LEE test show that the unit exceeds 10 percent of the emissions limit or exceeds the potential to emit 29 pounds of Hg per year, you will lose LEE status for the unit. You can regain LEE status for that unit if every required performance test for a 3-year period shows that emissions from the unit did not exceed the LEE limit. If LEE status is lost for a solid fuel unit, you must commence quarterly performance testing until you install, certify, and operate a Hg CEMS or a sorbent trap monitoring system, and you must complete the installation and certification within 6 months of losing LEE status; for a liquid fuel unit, you must commence quarterly performance testing.

d. If a liquid oil-fired EGU has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, you must demonstrate continuous compliance with the applicable work practice standard by conducting at least once every 36 calendar months (48 calendar months if a neural network is employed) a combustion process tune-up, a thorough equipment inspection, and an optimization to minimize generation of CO and NO_X, all meeting the requirements of this final rule. You must maintain and inspect the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO_X data using portable analyzers (which typically include handheld or similar devices). Specific details are addressed in 40 CFR 63.10021 of the final rule. In addition, you must record boiler operating hours, by fuel type, in each calendar quarter.

e. The rule allows a grant of LEE status to existing units with test results that show a history of low, non-mercury emissions. As mentioned earlier, LEE status reduces testing frequency for units. After a 3-year period during which every emissions test for a specific pollutant shows emissions no greater than 50 percent of the emissions limit, you may reduce the emissions testing frequency for that specific non-mercury pollutant to once every 36 months. If any subsequent emissions test for that pollutant exhibits emissions greater than 50 percent of the emissions limit, you must revert to the original emissions testing frequency until you re-establish a 3-year period of very low emissions no greater than 50 percent of the standard.

f. For liquid oil-fired units that demonstrate continuous compliance with quarterly performance tests for HCl and HF emission limits rather than through use of HCl and HF CEMS, the final rule requires a site-specific monitoring plan in addition to the quarterly tests. For these pollutants, there is unlikely to be any existing underlying monitoring (such as compliance assurance monitoring) that serves as an additional tool to ensure the source's operations remain consistent with operating conditions during a recent successful performance test. The requirement for a site-specific monitoring plan fills this gap and ensures that in between tests, the source continues to operate in a manner designed to maintain HCl and HF emissions in compliance with the emission limits under this rule. The appropriate parameters to monitor will depend on the compliance strategy employed by a specific source, and thus EPA is enabling the monitoring approach to be established on a case-by-case basis. Given the relatively small number of these units and the other compliance options available, we anticipate that this approach will apply to a small set of units. The monitoring plan will identify the parameters monitored, the monitoring methods, the QA/QC elements that apply, and the data reduction elements (including appropriate averaging periods, as applicable). See 40 CFR 63.10000(c)(2)(ii).

(3) *Work practice standard.* For the performance tune-up work practice requirements, you must demonstrate continuous compliance by conducting the work practice at least once every 36 calendar months (48 calendar months if a neural network is employed). The work practice involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type, as applicable, to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. A combustion tune-up will involve optimizing combustion of the unit consistent with manufacturer's instruction as applicable, or in accordance with best combustion engineering practice for that burner type.

H. What are the notification, recordkeeping and reporting requirements?

All new and existing sources in all subcategories must comply with certain requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 9 of this final rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting. You must submit a notification of compliance status report for each unit, according to the schedule required by 40 CFR 63.9(h) of the General Provisions, including a certification of compliance.

Except for units that use CEMS for continuous compliance, under this rule you must provide semiannual compliance reports, as required by 40 CFR 63.10(e)(3) of subpart A, that indicate whether a deviation from any of the requirements in the rule occurred and whether or not any process changes occurred and compliance certifications were reevaluated. As discussed below, we are finalizing a requirement to use the 40 CFR part 75-based Emissions Collection and Monitoring Plan System (ECMPS) for reporting emissions and related data for units using CEMS for most pollutants. Also, as discussed below, for the PM CPMS, PM CEMS, and performance test results, we require you to use EPA's WebFIRE [309] database for reporting.

This rule requires you to keep certain records to demonstrate compliance with each emission limit and work practice standard. The General Provisions to 40 CFR part 63 specify these recordkeeping requirements (see Table 9 to this subpart). Among other specific records, you must keep the following:

(1) All reports and notifications submitted to comply with this rule.

(2) Continuous monitoring data as required in this rule.

(3) Each instance in which you did not meet an emission limit, work practice requirement, operating limit, or other compliance obligation (*i.e.,* deviations from this rule).

(4) Daily hours of operation by each unit.

(5) As part of the general duty to keep all monitoring data, fuel moisture content of liquid fuel, if you elect to demonstrate compliance using that information.

(6) A copy of the results of all performance tests, monitor certifications, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with this rule.

(7) A copy of your site-specific performance evaluation test plans developed for this rule as specified in 40 CFR 63.8(e), if applicable.

(8) A copy of your acid gas control system parameter monitoring plan under 40 CFR 63.10000(c)(2)(ii).

You also must submit the following additional notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to this subpart.

[309] WebFIRE is the Internet version of FIRE. The Factor Information Retrieval (FIRE) Data System is a database management system containing EPA's recommended emission estimation factors for criteria and HAP. It includes information about industries and their emitting processes, the chemicals emitted, and the emission factors themselves.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 60 calendar days before the performance test and/or compliance demonstration is scheduled.

(4) Notification of Compliance Status 60 calendar days following completion of the performance test and/or compliance demonstration.

Electronic reporting is becoming a common element of modern life (as evidenced by electronic banking and income tax filing), and the EPA is beginning to require electronic submittal of environmental data. Electronic reporting is already common in environmental data collection and many media offices at EPA are reducing reporting burden for the regulated community by embracing electronic reporting systems as an alternative to paper-based reporting.

One of the major benefits of reporting electronically is standardization, to the extent possible, of the data reporting formats that provides more certainty to users of what data are required in specific reports. For example, electronic reporting software allows for more efficient data submittal and the software's validation mechanism helps industry users submit fewer incomplete reports. This alone saves industry report processing resources and reduces transaction times. Standardization also allows for development of efficient methods to compile and store much of the documentation required to be reported by this rule.

Use of Electronic Reporting System

We are requiring that you submit certain reports electronically. In addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with these reports will save industry, state, local, tribal agencies, the public, and the EPA significant time, money, and effort while also improving the transparency and quality of emission inventories and, as a result, air quality regulations.

The reports to be submitted electronically include all performance test reports, notification of compliance status reports, compliance, and continuous monitoring data summaries specified in 40 CFR 63.10031 of this rule. Performance tests are required to be conducted as described in 40 CFR 63.7 of the General Provisions. The data that must be submitted as the performance test report are also described in 40 CFR 63.7. These data must be submitted (except in limited cases) to EPA's WebFIRE database by using the electronic reporting tool (ERT) and the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX), as described below. The data requirements for the notification of compliance status and compliance reports are described in detail in the regulatory text (40 CFR 63.10031) of this rule, but they essentially mirror the requirements in 40 CFR 63.6 of the General Provisions. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX as described below. As required in 40 CFR 63.10031(f)(2) of the final rule, the continuous monitoring summaries are required to be submitted quarterly. The quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the PM CPMS. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX, as described below. This same approach will apply if a source elects to use a PM CEMS or receives approval to use a HAP metals CEMS as an alternative monitoring method.

The availability of electronic reporting for sources subject to the Subpart UUUUU will provide efficiency, improved services, better accessibility of information, and more transparency and accountability. Additionally, submittal of these required reports electronically provides significant benefits for regulatory agencies, industry, and the public. The compliance data electronic reporting system (CEDRI and CDX) is being developed such that once a facility's initial data entry into the system is established and a report is generated, subsequent data submittal will only consist of electronic updates to existing information in the system. Such a system will effectively reduce the burden associated with submittal of data and reports by reducing the time, costs, and effort required to submit and update hard copies of documentation. State, local, and tribal air pollution control agencies will also benefit from having access to the more streamlined and accurate electronic data submitted to the EPA. Electronic reporting will allow for an electronic review process rather than a manual data assessment, making review and evaluation of the source-provided data and calculations easier and more efficient. Electronic reporting will also benefit the public by generating a more transparent review process and increasing the ease and efficiency of data accessibility. Furthermore, electronic reporting will reduce the burden on the regulated community by reducing the effort involved in data collection and reporting activities. In the future, we anticipate there will be fewer and less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. Electronic reporting will substantially reduce this burden, because the EPA will already have these data available and consolidated in an electronic database named WebFIRE. We anticipate that using electronic reporting for the required reports will result in an overall reduction in reporting costs; for a discussion of the economic and cost impacts of electronic reporting, see section XII.D. of this preamble.

Another benefit of electronic data submittal is that these data will greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA will be able to ensure that emission factors, when updated, represent the most current range of operational practices.

Data entry of these electronic reports will be through the CEDRI that is accessed through EPA's CDX (*www.epa.gov/cdx*). Data submitted electronically through CEDRI will be stored in CDX as an official copy of record.

Once you have accessed CEDRI, you will select the applicable subpart for the report that you are submitting. You will then select the report being submitted, enter the data into the form, and click on the submit button. In some cases, such as with submittal of a notification of compliance status report, you will select the report icon, enter basic facility information, and then upload the report in a specified file format.

In addition, we believe that there will be value in allowing other reporting forms to be developed and used in cases where the other reporting forms can provide an alternate electronic file consistent with EPA's form output format. This approach has been used successfully to provide alternatives for other electronic forms (*e.g.*, income tax submittal).

In cases where performance test data are to be submitted to the EPA, you must enter the performance test data and information into the electronic reporting tool (ERT) which can be accessed at *http://www.epa.gov/ttn/chief/ert/index.html.* In CEDRI, the user must then upload the ERT file. CEDRI submits a copy of the ERT project data file directly to WebFIRE where the data are made available. Where performance test reports are submitted, WebFIRE notifies the appropriate state, local, or tribal agency contact that an ERT project data file was received from the source.

Submitting performance test data electronically to the EPA will apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at the ERT Web site listed above.

I. Submission of Emissions Test Results to the EPA

The EPA has determined that harmonization of the monitoring and reporting requirements of this final rule with 40 CFR part 75 is appropriate, where the affected industry already has a well-defined system for continuous monitoring and reporting of emissions under that part. Therefore, the Agency is finalizing monitoring and reporting requirements for most CEMS that are consistent with 40 CFR part 75. You must report CEMS data (other than PM CEMS data or data from alternative monitoring subject to site-specific approval such as a HAP metals CEMS) to the EPA electronically, on a quarterly basis, using the ECMPS.

The ECMPS process divides electronic data into three categories, the first of which is monitoring plan data. You must maintain the electronic monitoring plan separately and can update it at any time if necessary. The monitoring plan documents the characteristics of the affected units (*e.g.*, unit type, rated heat input capacity, etc.) and the monitoring methodology used for each parameter (*e.g.*, CEMS). The monitoring plan also describes the type of monitoring equipment used (hardware and software components), includes analyzer span and range settings, and provides other useful information. Nearly all coal-fired EGUs are subject to the ARP and thus have established electronic monitoring plans that describe their required SO_2, flow rate, CO_2 or O_2, and, in some cases, moisture monitoring systems. The EPA will adjust the ECMPS monitoring plan format to accommodate this same type of information for Hg, HCl, and HF CEMS, with the addition of a few codes for the new parameters.

The second type of data collected through ECMPS is certification and QA test data. These data include data from linearity checks, RATAs, cycle time tests, 7-day calibration error tests, and a number of other QA tests that are required to validate the emissions data. You may submit the results of these tests to the EPA as soon as you obtain the results, with one notable exception. Daily calibration error tests are not treated as individual QA tests, due to the large number of records generated each quarter. Rather, these tests must be included in the quarterly electronic reports, along with the hourly emissions data. The ECMPS system is set up to receive and process certification and QA data from SO_2, CO_2, O_2, flow rate, and moisture monitoring systems that are installed, certified, maintained, operated, and quality-assured according to 40 CFR part 75. EGUs routinely submit these data to the EPA under the ARP and other emissions trading programs.

To accommodate the certification and QA tests for Hg CEMS, other CEMS, and sorbent trap monitoring systems, the structure and functionality of ECMPS needs relatively few changes, because most of the tests are the same as those required for other gas monitors. For reporting Hg, HCl, SO_2, and HF CEMS data under this rule, we are disabling ECMPS' 40 CFR part 75 bias test (which is required for certain types of monitors under the EPA's SO_2 and NO_X emissions trading programs). The bias adjustment of the data from these monitors is unnecessary for compliance with the rule.

The third type of data collected through ECMPS is the hourly emissions data, which, as previously noted, is reported on a quarterly schedule. You must submit reports within 30 days after the end of each calendar quarter. The emissions data format requires hourly reporting of all measured and calculated emissions values, in a standardized electronic format. You must report direct measurements made with CEMS, such as gas concentrations, in a Monitor Hourly Value (MHV) record. A typical MHV record for gas concentration includes data fields for:

(1) The parameter monitored (*e.g.*, SO_2);

(2) The unadjusted and bias-adjusted hourly concentration values (note that if bias adjustment is not required, only the unadjusted hourly value is reported);

(3) The source of the data, *i.e.*, a code indicating either that each reported hourly concentration is a quality assured value from a primary or backup monitor, or that quality-assured data were not obtained for the hour; and

(4) The percent monitor availability (PMA), which is updated hour-by-hour. This generic record structure could easily accommodate hourly average measurements from CEMS used under this rule.

The ECMPS reporting structure is quite flexible, which makes it useful for assessing compliance with various emission limits. The Derived Hourly Value (DHV) record allows calculations of a wide variety of quantities from the reported hourly emissions data. For instance, if an emission limit is expressed in units of lb/MMBtu, the DHV record can be used to report hourly pollutant concentration values in these units of measure, since the lb/MMBtu values can be derived from the hourly pollutant and diluent gas (CO_2 or O_2) concentrations reported in the MHV records. The ECMPS can also accommodate multiple DHV records for a given hour in which more than one derived value is required to be reported. The system will support reporting hourly data in the units of the emission standards (*e.g.*, lb/MMBtu, lb/TBtu, lb/GWh, etc.) when hourly Hg concentration data are reported through ECMPS using the DHV record, in conjunction with the appropriate equations and auxiliary information such as heat input and electrical load (all of which are reported hourly in the emissions reports).

One change in this rule from standard 40 CFR part 75 emissions data reporting is elimination of the requirement to provide substitute data calculations within ECMPS. The ARP and other emissions trading programs that report emissions data to the EPA using 40 CFR part 75 require provision of a complete data record. Emissions data are required to be reported for every unit operating hour. When CEMS are out of service, substitute data must be reported to fill in the gaps. However, for the purposes of compliance with a NESHAP, reporting substitute data during monitor outages is not necessary, as quantification of total mass emissions is not the focus of the rule. Hours when a monitoring system is out of service would be counted as hours of monitor down-time and may be a deviation from the monitoring requirements of this rule unless the rule provides an exception, as it does for routine quality control and maintenance activities.

In contrast to the CEMS-related data that would be submitted through ECMPS, you must submit reports of performance tests and PM CPMS data to EPA's WebFIRE database by using CEDRI that is accessed through EPA's

CDX (*www.epa.gov/cdx*). You must submit performance test data in the file format generated through use of EPA's ERT (see *http://www.epa.gov/ttn/chief/ert/index.html*) within 60 days of performance test completion. Electronic data submittal requirements are described in section V.H. of this preamble.

Other notifications and reports not currently accepted by the electronic reporting system will be submitted in hardcopy form at this time.

VI. Summary of Significant Changes Since Proposal

The previous section described the requirements that EPA is finalizing in this rule. This section will discuss in greater detail the key changes EPA is making from the proposed. These changes result from EPA's review of the additional data and information provided to us and our consideration of the many substantive and thoughtful comments submitted on the proposal. While our approach and methodology to establishing the standards remain the same, the changes make the final rule more flexible and cost-effective, reduce reliability concerns and improve clarity, while fully preserving, or improving, the public health and environmental protection required by the CAA.

A. Applicability

Since proposal, the EPA has made certain changes to the applicability provisions of the final rule to provide clarity. These changes do not change the universe of sources subject to the rule.

The EPA is revising a number of the proposed definitions and adding a definition for ''natural gas-fired electric utility steam generating unit'' in the final rule to provide clarity to the regulated community concerning the standards applicable to coal- and oil-fired EGUs.

In the proposed rule, the EPA defined ''[e]lectric utility steam generating unit'' consistent with the CAA section 112(a)(8) definition:

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

40 CFR 63.10042.

We also indicated how we would determine whether units were coal-fired or oil-fired fired EGUs: ''If an EGU burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel (except solid waste as noted below), the unit is considered to be coal fired under this proposed rule. If a unit is not a coal-fired unit and burns only oil, or oil in combination with another fuel other than coal (except as noted below), the unit is considered to be oil fired under this proposed rule.'' 76 FR 25020.

We proposed a definition for the term ''fossil fuel-fired'' because that term was not defined in the statute and we wanted to clarify the level of fossil fuel combustion necessary to satisfy the CAA section 112(a)(8) definition of EGU. The definition focused on coal and oil combustion because the EPA was only regulating coal- and oil-fired EGUs in this final rule. The proposed definition contained two primary elements: (1) the unit must be capable of combusting sufficient amounts of coal or oil to generate the equivalent of 25 megawatts electrical output; and (2) the unit must have fired coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years. 76 FR 25025. We further stated that for a unit to be ''capable of combusting'' coal or oil the unit must have a permit that authorized the combustion of coal or oil and also have the appropriate fuel handling facilities on-site. *Id.*

As explained in the proposed rule, natural gas-fired EGUs were not included in the December 2000 listing so such units that otherwise met the CAA section 112(a)(8) definition of EGU because of natural gas combustion are not subject to the final rule. In the proposed rule, we stated that an EGU that ''combusts natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous 3 calendar years or 85.0 percent or more of the annual heat input during any one of those calendar years'' was not subject to the rule. *Id.* The references to 90 percent natural gas combustion over 3 years and 85 percent natural gas combustion in any one year were included to align with the definitions of ''fossil fuel-fired'' so that it would be clear that units combusting primarily natural gas would not be considered coal-fired, oil-fired, or IGCC EGUs if they burned 10 percent or less of coal, oil, or synthetic gas derived from coal or solid oil over 3 years or 15 percent or less of such fuels in any one year. We did not intend to suggest that to be considered a fossil fuel-fired EGU a natural gas-fired unit that is not a coal-fired or oil-fired EGU would have to combust natural gas that exceeded the 10 percent/15 percent thresholds set forth in the proposed rule. In fact, in 40 CFR 63.9983 of the proposed rule, we stated that ''[a]ny EGU that is not a coal- or oil-fired EGU and combusts natural gas more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years'' is not subject to this subpart.

We further explained that the percentages included in the definition of ''fossil fuel-fired'' would prevent units that primarily combusted fuels other than fossil fuels from being subjected to the final rule:

> Units that do not meet the definition of fossil-fuel fired would, in most cases, be considered IB units subject to one of the Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.,* less than or equal to 250 MMBtu/hr and used less than 10.0 percent of the average annual heat input during the previous 3 calendar years or less than 15.0 percent of the annual heat input during any one of those calendar years) is not considered to be a fossil fuel-fired EGU under this proposed rule. The EPA has based its threshold value on the definition of ''oil-fired'' in the ARP found at 40 CFR 72.2. As EPA has no data on such use for (*e.g.*) biomass co-fired EGUs because their use has not yet become commonplace, we believe this definition also accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this proposed rule. *Id.*

Thus, in the proposed rule, we intended to create thresholds to determine when a unit is fossil fuel-fired and for which fossil fuel the unit is fossil fuel-fired. We intended to include a unit combusting more than the defined amount of coal in one of the coal-fired EGU subcategories. If a unit is not coal-fired and it is combusting more than the defined amount of oil, we intended to include the unit in one of the oil-fired EGU subcategories. We also intended to make clear that EGUs that are neither coal-fired nor oil-fired but combust more than the defined amount of natural gas are natural gas-fired EGUs not subject to the final standards. However, the definitions, as proposed, were not sufficiently descriptive.

For example, we included a definition for ''coal-fired electric utility steam generating unit'' that did not include the requirement that the unit must combust coal for at least 10 percent of the heat input over 3 years or 15 percent of the heat input in any one year. Instead, in the proposed rule we indicated that a unit was coal-fired if it burned coal in any amount. We did not intend to define a unit as coal-fired if it burned coal that accounted for 10 percent or less over 3 years or 15 percent of less in any one year, as that would be inconsistent with the definition of fossil fuel-fired and the definitions for the oil-fired EGU subcategories. Under the proposed rule construct, a unit that combusts mostly biomass and less than 10 percent coal over 3 years would not be a coal-fired EGU because it would not meet the ''fossil fuel-fired'' definition. But a unit burning mostly petroleum coke and less than 10 percent coal over 3 years might be considered a coal-fired EGU because it would meet the definition of ''fossil fuel-fired'' and be burning some coal, even though that level of coal combustion alone would not be sufficient to make the unit ''fossil fuel-fired'' for coal. That result is at odds with our intent. The same would hold true for an EGU that combusts mostly natural gas and less than 10 percent synthetic gas derived from coal over a 3-year period. Our proposal preamble makes clear that we did not intend this result because we specifically stated that units burning 90 percent or more natural gas over a 3-year period would be considered natural-gas fired EGUs. 76 FR 25025.

In addition, we proposed to define ''[u]nit designed to burn solid oil fuel subcategory'' to include any EGU that burned a solid fuel derived from oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, either alone or in combination with other fuels. We also included the 10 percent/15 percent thresholds in the definition for the liquid oil subcategory, but, as stated above, we did not include the thresholds in the definition of ''coal-fired'' EGU. Therefore, there would be some confusion for a source that blended coal with solid oil derived fuel (*e.g.,* petroleum coke). For example, the owner or operator of an EGU that burned sufficient solid oil-derived fuel that accounted for 80 percent of the heat input in a given year and the remainder of the fuel was coal would not be sure which standard applied because the definitions in the proposed rule were internally inconsistent.

For these reasons, we are revising the definitions for ''coal-fired electric utility steam generating unit,'' ''integrated gasification combined cycle electric utility steam generating unit,'' and ''oil-fired electric utility steam generating unit,'' and we are adding a definition of ''natural-gas fired electric utility steam generating unit'' as set out in 40 CFR 63.10042.

In addition to these changes, we are revising the definition of ''fossil fuel-fired'' based on comments. We are revising the definition to remove the heat input equivalent of 25 MW because commenters noted that the equivalency used (taken from 40 CFR part 60, subpart Da) could not be applied consistently because of differing boiler efficiencies. Commenters noted that owners/operators were familiar with the use of the ''MW'' term for the boilers and boilers include nameplate capacities that are readily identifiable.

We are also including a revision to the definition so that the fossil fuel combustion thresholds of 10 percent over 3 consecutive years and 15 percent in one year are evaluated after the applicable compliance date of the final rule on a rolling basis. Commenters correctly noted that some existing coal- and oil-fired EGUs will convert their units to alternative fuels (*e.g.,* natural gas or biomass) and if the definition were finalized as proposed such units could be improperly subjected to the final standards.

The new definition is set out in 40 CFR 63.10042.

For clarity, we are also removing the definition of ''[u]nit designed to burn liquid oil fuel subcategory,'' revising the definition of ''[u]nit designed to burn solid oil fuel subcategory,'' adding definitions for the continental and non-continental liquid oil-fired EGU subcategories, and adding a definition of a limited-use liquid oil-fired EGU as set out in 40 CFR 63.10042.

In the proposed rule, we stated that we believed EGUs may at times not meet the definition of an EGU subject to this subpart. For example, we explained that there may be some cogeneration units that are determined to be covered under the Boiler NESHAP. Such unit(s) may make a decision to increase the proportion of production output being supplied to the electric utility grid, thus causing the unit(s) to meet the EGU cogeneration criteria (*i.e.,* greater than one-third of its potential output capacity and greater than 25 MW). In the preamble to the proposed rule, we indicated that a unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the EGU NESHAP for the 6-month period after the unit meets the EGU definition.[310] 76 FR 25026. Assuming the EGU did not meet the definition of an EGU following that initial occurrence, at the end of the 6-month period it would revert back to being subject to the Boiler NESHAP, or other applicable standard. We solicited comment on the extent to which situations like this might occur, how the EPA should address situations where units change applicability, and whether we should include provisions similar to those included in the final CISWI (40 CFR 60.2145) to address such situations. *Id.*

Several commenters asked the Agency to include provisions in the final rule that would address situations like the ones described in the preamble to the proposed rule. Because applicability to the final rule is based in part on the statutory definition of an EGU is CAA section 112(a)(8), similar to the situation with units combusting solid waste under CAA section 129(g)(1) (*e.g.,* CISWI Rule), we are adopting provisions in the final rule that are based on the fuel switching provisions of the final CISWI Rule (*See* Final CISWI Rule, 40 CFR 60.2145). For example, a cogeneration unit that did not historically provide more than one third of its potential electrical output capacity to a power distribution system could change its output and provide more than 25 megawatts electrical output to any power distribution system for sale. Such units would be subject to MATS. If the cogeneration unit later reduced its output such that it no longer met the definition of an EGU, that source would nevertheless remain subject to MATS for at least 6 months from the date that the unit first qualified as an EGU.

In addition, we are finalizing a provision whereby you may opt to remain subject to the provisions of this final rule, unless you combust solid waste, in which case you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.,* 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units), or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units)). We believe the provision to opt to remain subject to this final rule will ameliorate conditions where EGUs may potentially move between NESHAP on a relatively frequent basis. Notwithstanding the provisions of this final rule, an EGU that starts combusting solid waste is subject to standards under CAA section 129, and the unit remains subject to those standards until the unit no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

[310] Although we clearly stated the intent to require sources to comply for 6 months after meeting the definition of an EGU, we inadvertently failed to include the provision in the proposed rule.

The changes to the definitions described above provide clarity to sources, permitting agencies, and the public about the applicability of the rule and help ensure that sources are appropriately covered by the regulation.

B. Subcategories

In this final rule, the EPA is adding subcategories for limited-use oil-fired units and non-continental oil-fired units and revising the definitions for the coal-fired EGU subcategories.

The proposed rule subcategorized EGUs burning coal into two subcategories: EGUs designed for coal ≥8,300 Btu/lb and EGUs designed for virgin coal <8,300 Btu/lb (low rank virgin coal). We received a number of comments indicating that the definition of the low rank virgin coal subcategory was technically deficient.

Under CAA section 112(d)(1), the Administrator has the discretion to ''* * * distinguish among classes, types, and sizes of sources within a category or subcategory in establishing * * *'' standards. The EPA maintains that, normally, any basis for subcategorization (*i.e.,* class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. *See* 76 FR 25036–25037. The EPA believes it is not reasonable to exercise our discretion without such a difference because if sources can achieve the same level of emissions reductions notwithstanding a difference in class, type, or size, the purposes of CAA section 112 are better served by requiring a similar level of control for all such units in the category or subcategory. *See Lignite Energy Council* v. *EPA,* 198 F. 3d 930, 933 (D.C. Cir. 1999) (''EPA is not required by law to subcategorize—section 111[b][2] merely states that 'the Administrator *may* distinguish among classes, types, and sizes within categories of new sources''' (emphasis original)); *see* also CAA section 112(d)(1) (containing almost identical language to CAA section 111, CAA section 112(d)(1) provides that ''the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing [ ] standards * * *''). Even if we determine that emissions characteristics are different for units that differ in class, type, or size, the Agency may still decline to subcategorize if there are compelling policy justifications that suggest subcategorization is not appropriate. *Id.*

When developing the proposed rule, we examined the EGUs in the top performing 12 percent of sources for Hg emissions. We determined that:

> There were no EGUs designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units. The boiler of a coal-fired EGU designed to burn coal with that heat value is bigger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories. For all other HAP from these two subcategories of coal-fired units, the data did not show any difference in the level of the HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for the other HAP. 76 FR 25036–67.

Based on this determination, we proposed to establish two subcategories with separate Hg limits. Comments on the proposed rule indicate that we correctly identified the EGUs that should be included in each subcategory, but the comments also demonstrated that we made certain incorrect conclusions that require us to revise the definitions of our coal-fired EGU subcategories. The revised definitions ensure that the EGUs we identified at proposal as having different Hg emissions remain in one subcategory.

As stated above, we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) (low rank virgin coal) that causes the disparity in Hg emissions. Several commenters indicated that their EGUs were designed to burn and burned low rank virgin coal but the units did not meet the height-to-depth ratio that EPA proposed. For example, the height-to-depth ratio of certain EGUs in this subcategory is in fact 3.5, not 3.82. Further, there are other EGUs in this subcategory that are circulating fluidized bed (CFB) combustion units which do not meet the height-to-depth ratio parameters in the proposed rule, nor are they anything like the pulverized coal (PC) EGUs we initially identified as having the 3.82 height-to-depth ratio.

In addition to the comments concerning EGUs firing this coal, we received comments from at least two commenters indicating that the EPA should clarify in which subcategory a unit belongs when it does not burn low rank virgin coal but is designed to combust low rank virgin coal and has a height-to-depth ratio of greater than 3.82. Commenters also indicated that CFB units that are burning coal-refuse [311] or other nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or greater are ''designed to burn'' any type of coal. Owners of CFB units that are not firing low rank virgin coal asked which subcategory they belong to based on their ability to burn any type of coal (including low rank virgin coal) without modification. These commenters also indicated that some coal refuse that is combusted has a heating value less than 8,300 Btu/lb but is not ''virgin coal.'' It was unclear to which subcategory they belonged since the proposed rule did not in fact require the unit to burn any specific coal, instead only requiring the unit be ''designed'' to burn lower Btu coal.

Based on the comments received, we reevaluated the subcategory definitions because we were concerned that the definitions we proposed would improperly categorize a number of the EGUs in both subcategories. We concluded that we should not maintain the proposed definition for ''[u]nits designed for coal <8,300 Btu/lb'' and exclude the CFB units and PC EGUs with a height-to-depth ratio less than 3.82 that combusted low rank virgin coal.

We were equally concerned that the subcategory definitions not be revised in a manner that would move EGUs that we believed the data show could comply with a more stringent standard into a subcategory with a less stringent standard because, aside from the type of EGUs we identified, all other classes, types, and sizes of EGUs were represented among the top performing 12 percent for Hg in the ≥8,300 Btu/lb subcategory. We were particularly concerned about the CFB units because other CFB units are well represented among the best performing EGUs for Hg in the ≥8,300 Btu/lb subcategory, but the CFB units burning low rank virgin coal are not achieving the same levels of Hg emissions control. Including the best performing CFB units from the other subcategory in the low rank virgin coal subcategory would likely lead to a Hg standard as stringent as the standard for

[311] It is our understanding that no unit combusts coal-refuse from nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb).

EGUs in the ≥8,300 Btu/lb subcategory because the CFB units from the other subcategory would be used to establish the floor. We believe that result would be inconsistent with the intent of the proposed rule. We were also concerned about the information that some EGUs that fired low rank virgin coal had a height-to-depth ratio of 3.5, not 3.82, and that some EGUs that fired other ranks of coal had a height-to-depth ratio greater than 3.82. For these reasons, we did not revise the definition to include CFB units and PC EGUs with a height-to-depth ratio greater than 3.5.

After fully considering the available information, including the comments received, we have concluded that it is appropriate to continue to base the subcategory definitions, at least in part, on whether the EGUs were designed to burn and, in fact, did burn low rank-virgin coal, but that it is not appropriate to continue to use the height-to-depth ratio criteria because that approach would potentially exclude EGUs we identified as having different Hg emission characteristics and include EGUs that did not have different emissions characteristics. We recognize that some commenters have taken the position that it is unlawful to subcategorize based on factors such as fuel type but nothing in the statute prohibits such an approach and the case law supports this approach to the extent courts have considered subcategorization based on such factors. *See Sierra Club* v. *Costle,* 657 F. 2d 298, 318–19 (D.C. Cir. 1981) (differing pollutant content of input material can justify a different standard based on subcategorization authority to ‘‘distinguish among classes, types and sizes within categories of new sources’’). Furthermore, we believe had Congress intended to prohibit the EPA from subcategorizing based on an EGU being designed to use and using a certain material input (*e.g.,* fuel) it would have clearly stated such intent in the CAA. However, we believe the Agency could decline to exercise its discretion to subcategorize even if the potential result would be the prohibition of the use of some materials if the circumstances warranted. We note that even if we did not subcategorize on the final basis selected, the Hg emissions standard of 1.2E0 lb/Tbtu for the ‘‘unit designed for coal ≥8,300 Btu/lb’’ would remain the same.

We considered basing the subcategory solely on an EGU being designed to burn and burning low rank virgin coal. We decided not to do so because we were concerned that such a definition would allow sources to potentially meet the definition by combusting very small amounts of low rank virgin coal. For example, an EGU on the east coast (or any other region) that was not designed to burn and did not routinely burn low rank virgin coal could import one truck full of low rank virgin coal and burn a very small quantity of it periodically to meet the subcategory definition. To avoid creating this potential loophole, we considered other characteristics that would distinguish EGUs combusting low rank virgin coal.

We determined that these EGUs are universally constructed ‘‘at or near’’ a mine containing low rank virgin coal because it is not cost-effective to transport large quantities of such fuel long distances. Furthermore, we believe that this subcategory of EGUs are almost always built at a mine and limited transportation of the coal is only required as the mine face moves over the course of time. Many such EGUs construct dedicated rail lines, private roads, or conveyor systems to transport the coal to the EGU as the mine face moves. We obtained information from data acquired to develop the CSAPR indicating that the longest distance any EGU firing low rank virgin coal transports that coal is 40 miles. We believe that this distance is near the outer limits for the transport of such coal, but, even for those EGUs, the EGUs were constructed closer to a now idle mine or closer to the working face of a mine that has now expanded away from the EGU site. For these reasons, we are including a requirement that the unit be constructed and operated at or near a mine containing the low rank virgin coal it burns.

We are revising the coal-fired EGU subcategory definitions as set out in 40 CFR 63.10042.

We believe the revised subcategory definitions are reasonable for all the reasons set forth above. The revised definitions maintain the EGUs we identified as having different Hg emissions characteristics in one subcategory and the definitions prevent other EGUs that are not firing low rank virgin coal from being required to comply only with the less stringent Hg emission standard.

As discussed in response to comments, we do not believe that additional subcategorization of other coal-fired EGUs is reasonable or appropriate. All other coal-fired EGUs that are not designed to burn and are burning low rank virgin coal are represented among the best performing sources for Hg, such that no argument exists to support that the Hg emissions from those EGUs are different. In any case, even if emissions are somewhat different as some commenters suggest, we would decline to exercise our discretion because the data demonstrate that the best performing EGUs designed to burn and burning all other ranks of coal are able to achieve the MACT level of control using currently available controls and other HAP emission reduction mechanisms (*e.g.,* coal washing) for the ≥8,300 Btu/lb subcategory.

A second issue related to subcategorization concerns non-continental liquid oil-fired EGUs. At proposal, the EPA did not have sufficient emissions data from non-continental liquid oil-fired EGUs upon which to base a subcategory and took comment on the issue. The data have since been provided in response to the ICR and we received comments suggesting that a non-continental subcategory is appropriate based on the location of such units, the limited availability of alternative fuel sources, and the fact that the emissions characteristics of such units are distinct from continental liquid oil-fired EGUs. The EPA has evaluated the data and comments and we agree that a subcategory is warranted based for the reasons suggested by the commenters. Therefore, the Agency is finalizing the liquid oil-fired EGU subcategories of ‘‘continental’’ and ‘‘non-continental.’’

Lastly, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal because some sources required to test under the ICR did not submit the data until after proposal. We took comment on whether a limited-use subcategory was warranted. Commenters indicated that their units were a different class and type of units because many of them were only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.,* they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate. Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil-fired EGUs as discussed further elsewhere in this preamble.

C. Emission Limits

The proposed rule included numerical emission limits for PM, Hg, HCl, HF, SO_2, total HAP metals, and individual HAP metals, depending on the subcategory and specific situation. These proposed limits resulted from calculations of MACT floors using information and data available to the Agency prior to proposal, as required by CAA section 112. Based on information and data received during the comment period, we have made data and calculation corrections where necessary and then re-ranked the best performing units in the MACT floor pools. Based on the new ranking, a limited number of the emission limits in the final rule have changed from those proposed.

In addition to adjustments to the emission limits themselves, we are finalizing several other changes to the emission standards that will simplify and improve compliance for sources without compromising the toxics reductions achieved. One key change, as discussed elsewhere in this notice, is that we have changed the surrogate for non-mercury metallic HAP from total particulate matter (PM) to filterable PM for coal-fired and solid oil-derived EGUs. This change is based on information provided in comments and our own conclusion that measurement of filterable PM provided assurance of equivalent HAP emissions control. Most of the non-mercury metal HAP, for which PM is a surrogate, are filterable PM and the one that is not (Se) is well controlled by the limit on acid gases. Using filterable PM as the surrogate will allow us to use continuous PM monitoring systems, which measure filterable (but not total) PM, thereby providing a more continuous measure of compliance.

For liquid oil-fired EGUs, based on comments received and corrections made to the data submitted, we have added a filterable PM limit in the final rule as an alternative equivalent standard for the total metal-HAP limit in the proposed rule. In addition, as discussed elsewhere in this notice, we have added measurement of the moisture content of the oil (with a 1 percent limit) as an alternate compliance assurance measure for liquid oil-fired EGUs for determining compliance with the HCl and HF limits. Direct measurement of HCl and HF remains a compliance demonstration method in the final rule. Finally, as discussed in section VI.D of this notice, the final work practice standard consisting of burner tune-ups, much like those required for organic HAP control, for those limited-use liquid oil-fired EGUs whose annual capacity factor is less than 8 percent.

D. Work Practice Standards for Organic HAP Emissions

As noted earlier in section V.D., the final rule includes a work practice standard for organic HAP, including dioxins and furans, applicable to all EGUs. As noted in section V.D. above, the majority of emissions of these pollutants are below the detection levels of EPA test methods and, therefore, are impractical to measure. The work practice standard, described below, is a practical approach to ensuring that equipment is maintained and run so as to minimize emissions of dioxins and furans, and we expect it to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. The work practice also applies to the limited-use liquid oil-fired subcategory included in the final rule.

The work practice involves maintaining and inspecting the burners and associated combustion controls (as applicable), tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after the burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. In Table 3 of the final regulation, we have clarified that this refers to performance tune-ups, not tests, and have addressed the frequency requirement as discussed in response to comments about the appropriateness of the 18-month frequency. The provisions of 40 CFR 63.10006(h)(i) refer to 40 CFR 63.10021(e) for the specific steps required to be part of the periodic tune-up. We have also adjusted the language in the final rule to recognize the value of automated boiler optimization tools such as neural network systems.

Under the final rule, the tune-up must be conducted at each planned major outage and in no event less frequently than every 36 calendar months, with an exception that if the unit employs a neural-network system for combustion optimization during hours of normal unit operation, the required frequency is a minimum of once every 4 years (48 calendar months). Initial compliance with the work practice standard of maintaining burners must occur within 180 days of the compliance date of the rule. The initial compliance demonstration for the work practice standard of conducting a tune-up may occur prior to the compliance date of the rule, but must occur no later than 42 months (36 months plus 180 days) from the compliance date of the rule or, in the case of units employing neural network combustion controls, 54 months (48 months plus 180 days). If the tune-up occurs prior to the compliance date of the rule, you must maintain adequate records to show that the tune-up met the requirements of this standard.

We have made a number of specific changes to address what to do for repairs that may require longer term corrective actions, additional methods for evaluating combustion effectiveness, and clarification on procedures for recording CO and NO_X information. There were specific comments that opposed the reference to manufacturer specifications, if available. We retained this language in the final rule, but note that these specifications apply only to the extent applicable. Specifically, if manufacturer specifications only address equipment or conditions that are no longer present given current boiler operations, then those specifications are not applicable and other combustion engineering best practice procedures for that burner type would apply. We have also clarified that portable emission monitoring equipment may be used to collect the required emissions optimization data regarding pre- and post-tune-up CO and NO_X emission levels.

E. Requirements During Startup, Shutdown, and Malfunction

We proposed numerical emission standards that would apply at all times, including during periods of startup, shutdown, and malfunction. Although at proposal we stated that we were not setting a different standard for startup and shutdown, we did propose different standards for startup and shutdown by our inclusion of the default values described below, which applied only during startup and shutdown. Specifically, we stated:

> To appropriately determine emissions during startup and shutdown and account for those emissions in assessing compliance with the proposed emission standards, we propose use of a default diluent value of 10.0 percent O_2 or the corresponding fuel specific CO_2 concentration for calculating emissions in units of lb/MMBtu or lb/TBtu during startup or shutdown periods. For calculating emissions in units of lb/MWh or lb/GWh, we propose source owners use an electrical production rate of 5 percent of rated capacity during periods of startup or shutdown. We recognize that there are other approaches for determining emissions during periods of startup and shutdown, and we request comment on those approaches. We further solicit comment on the proposed approach described above and whether the values we are proposing are appropriate.

We proposed application of the respective emission limits during periods of startup and shutdown and use of default values to calculate the emission limits. The standards that apply at all times other than startup and shutdown are production-based limits, which is why we proposed the default values. The default values were meant to account for the fact that during startup and shutdown events, production (in this case the generation of electricity) is by definition nonexistent. Thus, in effect, we proposed a separate standard to apply during startup and shutdown.

We received a variety of comments on the proposed standards that would apply during startup and shutdown. Many commenters pointed to the lack of data in the record concerning emissions that occur during periods of startup and shutdown. They further asserted that emissions during these periods can be highly variable in light of the sequence of events that occurs during the startup and shutdown of an EGU. Although a number of commenters supported the use of the diluent factor approach, including the default 5 percent of rated capacity, during startup/shutdown periods, other commenters questioned the feasibility of collecting additional data during such periods and had concerns regarding the reliability of measurements obtained from EGUs during such periods.

In response to the Agency's ICR to the utility industry, seven owners or operators indicated that they provided startup and shutdown data for their EGUs. These data were submitted in response to the requirement in the ICR to provide all available data from the 5 years prior to the date the ICR was issued. Of these data, there were almost no HAP data for startup and shutdown periods and almost all of the data failed to meet our data quality requirements.[312] Thus, we do not have sufficient data on emissions that occur during startup and shutdown on which to set emission standards. We are therefore establishing work practice standards rather than numeric emissions standards for periods of startup and shutdown in the final rule. Before we describe those work practices, we first address what constitutes startup and shutdown.

Several commenters had an expansive view of what constitutes startup and shutdown. We disagree with these commenters that asserted that periods of ''load swings'' should be considered ''startup'' or ''shutdown,'' as they are generally routine, normal operations with production (*i.e.,* generation of electricity) taking place. We maintain that the standards as promulgated account for any variability in emissions that may occur during these periods over a 30-day averaging period, and commenters have provided no data that cause us to doubt that determination. We have included definitions of startup and shutdown in the final rule that are consistent with the definitions in the proposed rule. At proposal, we defined startup as the setting in operation of an affected source or portion of an affected source for any purpose, and shutdown as the cessation of operation of an affected source or portion of an affected source for any purpose.

Commenters sought more clarity regarding the meaning of these terms as applied to EGUs, so we are revising the definitions in the final rule as set out in 40 CFR 63.10042.

These interpretations are tailored for EGUs and are consistent with the definitions of ''startup'' and ''shutdown'' contained in the 40 CFR part 63, subpart A General Provisions. We believe these revised definitions address the comments and are rational based on the fact that EGUs function to provide electricity primarily for sale to the grid but also at times for use on-site; therefore, EGUs should be considered to be operating normally at all times electricity is generated. We further believe these revised definitions address what some commenters describe as ''warm'' and ''hot'' startups as long as the EGU is shutdown (*i.e.,* no fuel fired and no electricity generation) prior to the ''warm'' or ''hot'' startup period.

As for the work practices, in this final rule, the EPA is requiring sources to operate using either natural gas or distillate oil for ignition during startup. The EPA also is requiring sources to vent emissions to the main stack(s) and operate all control devices necessary to meet the normal operating standards under this final rule (with the exception of dry scrubbers and SCRs) when coal, solid oil-derived fuel, or residual oil is fired in the boiler during startup or shutdown. It is the responsibility of the operators of EGUs to start their dry scrubber and SCR systems appropriately to comply with relevant standards applicable during normal operation.

The EPA carefully considered fuels and potential operational constraints of air pollution control devices (APCDs) when designing its work practices for periods of startup and shutdown. The EPA notes that there is no technical barrier to burning natural gas or distillate oil for longer portions of startup or shutdown periods, if needed, at a boiler, and the HAP emission reduction benefits warrant additional utilization of such fuels until the temperature and stack emissions pressure is sufficient to engage the APCDs. The EPA is aware that SCR systems with ammonia injection need to be operated within a prescribed and relatively narrow temperature window to provide NO_X reductions. Further, the EPA is aware that dry scrubbers also need to be operated close to flue gas saturation temperature. Because these devices have specific temperature requirements for proper operation, the EPA notes in its work practices that it is the responsibility of the operators of EGUs to start their SCR and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

Some commenters have asserted that firing of fuel oil during periods of startup and shutdown constrains operation of PM controls (ESPs and baghouses) because under cooler conditions, acids and tars can condense on surfaces in these controls. The commenters assert that such condensation can cause detrimental impacts on hardware and operation of these controls, and could cause safety concerns. The EPA understands that concerns with acidic and tarry deposits are related to firing of heavy (residual) oil and not distillate oil. Accordingly, with residual fuel oil firing, site-specific flue gas temperature and oxygen (O_2) concentration thresholds may be applicable to minimize condensation of acids and tars and thereby minimize any potential for detrimental impacts on hardware and any safety concerns.

[312] In response to the ICR, we also received SO_2 CEMS data and the Agency had additional SO_2 CEMS data available through the CAMD ARP database. We are not able to identify specific periods of start-up and shutdown in either the ICR CEMS data or the CAMD ARP data, and the ICR respondents do not indicate that the ICR data includes periods of startup and shutdown. We set the emission limits for SO_2 and HCl using the data provided to the EPA from the 2010 ICR, not the CAMD data, since those data were taken concurrently under the same specified operating conditions using the same fuel. We used the SO_2 CEMS data that was submitted in response to the ICR by converting it to single point data to correlate to the data from units that did not provide CEMS data from the relevant testing period. The emissions limits for the NESHAP incorporated variability by applying the 99 percent UPL to the average emissions developed from the stack test data and SO_2 CEMS data that was converted to stack test data. Thus, we did not have data on which to establish an SO_2 standard during periods of startup and shutdown and the numeric standards do not apply to those periods in the final rule. In contrast, the NSPS for SO_2 is applicable during periods of startup and shutdown since the long term CAMD ARP CEMS data were used to determine the average performance of the best demonstrated technology. Those long term data were assumed to incorporate process variability including that associated with fuel and process/operational changes and periods of startup and shutdown.

However, the EPA notes that its work practice requirements provide flexibility to the operator to take appropriate site-specific remedial measures, if needed. The EPA further notes that boilers have several options to prevent detrimental impacts by: (1) Using startup fuels, natural gas or distillate oil, until appropriate flue gas conditions have been reached and then fire residual oil; (2) pre-coating the PM control surfaces [313] with an alkaline powder (*e.g.,* limestone); (3) installing chemically resistant bags [314] in baghouses if applicable; and (4) using low-sulfur oils. The EPA also notes that currently the industry has many operational residual oil-fired boilers that are started up with either natural gas or distillate fuel oil. At these boilers, the transition from the startup fuel, distillate oil or natural gas, to residual oil is already being practiced without unacceptable impacts on APCDs including PM controls, which are operated to meet applicable opacity limits. Based on this experience and the options described above, those boilers where residual oil is used for either a part of the startup period, or as the main fuel, will also be able to operate their PM controls to meet the work practice requirements of the rule. Note that coal firing is done at high enough temperatures that concerns with condensation are not relevant. None of the commenters have specifically commented on this aspect of coal firing.

The EPA is not aware of any operational constraints applicable to operation of wet scrubbers during startup that could cause detrimental impacts on wet scrubber hardware and safety concerns and none of the commenters have commented on this aspect of wet scrubber operation.

Finally, the EPA notes that dry sorbent injection (DSI) can be applied across a very broad temperature range and will be engaged when residual oil or coal is fired in a boiler to comply with HCl requirements. Again, no comments have been received on this aspect of DSI operation.

This final rule requires work practice standards for emissions during startup and shutdown, and the rule requires sources to measure and report their emissions at all times, including periods of startup and shutdown, when continuous monitoring is used to demonstrate compliance. Data collected under this final rule will provide the EPA with information to more fully analyze this issue and address it during the 8-year review established under CAA section 112.

We now address malfunctions. In contrast to the exclusion of startup and shutdown period emissions from 30-boiler operating day rolling average emissions, the final rule requires inclusion of emissions during periods of source or APCD malfunction. We have concluded that when combined with the availability of an affirmative defense as described below, this is an appropriate and practical approach.

As mentioned earlier, periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, 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 63.2). The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. Under CAA section 112, emissions standards for new sources must be no less stringent than the level ''achieved'' by the best controlled similar source and for existing sources generally must be no less stringent than the average emission limitation ''achieved'' by the best performing 12 percent of sources in the category. There is nothing in CAA section 112 that directs the Agency to consider malfunctions in determining the level ''achieved'' by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with the CAA section 112 case law, nothing in that case law requires the Agency to consider malfunctions as part of that analysis. Clean Air Act section 112 uses the concept of ''best controlled'' and ''best performing'' unit in defining the level of stringency that CAA section 112 performance standards must meet. Applying the concept of ''best controlled'' or ''best performing'' to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

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 (D.C. 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.''). *See also, Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (D.C. 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.''). 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 CAA section 112, and we believe it is a reasonable interpretation of the statute. This approach to malfunctions has been used consistently in CAA section 112 and CAA section 129 rulemaking actions since the D.C. Circuit's decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008) vacated the SSM exemption contained in CFR 63.6(f)(1) and 40 CFR 63.6(h)(1). (*See, e.g.,* National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants, 75 FR 54970 (September 9, 2010); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units; Final Rule, 76 FR 15372 (March 21, 2011).

In the event that a source fails to comply with the applicable CAA section 112(d) 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

[313] Coal Power, May 1, 2007: *http://www.coalpowermag.com/plant_design/Coal-Plant-O-and-M-River-Locks-and-Barges-Are-an-Aging-Workforce-Too 36.html.*

[314] Neundorfer: Lesson #r, p.4–7, Table 4–1: *http://www.neundorfer.com/FileUploads/CMSFiles/Fabric%20Filter%2OMaterial [0].pdf.*

to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 63.2 (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)). The EPA is therefore adding to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. *See* 40 CFR 63.10042 (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 have added 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 63.10001. (*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 63.2 (*i.e.,* sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation). For example, to assert the affirmative defense successfully, 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 63.10001 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 CAA section 113 (*see* also 40 CFR 22.27).

The EPA is including an affirmative defense in the final rule as we have in other recent MACT rules so as to balance the 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 (D.C. 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. While ''continuous'' limitations, on the one hand, are required, there is also case law indicating that in some 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 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 ''variant provisions'' such as provisions allowing for upsets during startup, shutdown and equipment 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 (D.C. Cir. 1973). Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments calls into question 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 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to ensure both 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.

F. Testing and Initial Compliance

We have carefully evaluated the wide-ranging comments on testing, continuous monitoring, and other provisions regarding initial compliance demonstrations, and we have made adjustments intended to help streamline implementation while still ensuring adequate demonstration of compliance with the emission limits and other standards established under this final rule. The significant changes include:

1. No Fuel Analysis Requirements

Apart from an alternative that allows you to analyze fuel moisture for liquid oil-fired EGUs rather than measuring HCl and HF, the final rule does not include any of the fuel analysis requirements that were in the proposed rule, either as part of initial compliance demonstrations or ongoing compliance demonstrations. In reviewing the results of the fuel analyses and the expected range of results that would be received from laboratories conducting the proposed analyses, we determined that too many results would be returned as ''below detection level'' and, thus, provide little information to assist with rule implementation and compliance oversight. Given the costs and efforts involved, we determined that the proposed fuel analysis requirements would not be an effective compliance monitoring tool for this final rule.

2. Clarification of Testing

We have clarified that where options for emission limits apply (such as filterable PM versus non-mercury HAP metals, or SO_2 versus HCl), you need only perform stack testing to demonstrate compliance with the selected emission limit. For example, if you elect to meet the individual non-mercury HAP metals standards, you must conduct the Method 29 test for the metals, and you do not have to conduct a Method 5 test for PM.

3. Low Emitting EGU Qualification

We have significantly modified the proposed requirements to qualify as a LEE unit for a pollutant other than Hg based on an initial performance test. Under the proposed rule, the operating limit monitoring provided additional assurance of compliance for a source qualified for non-mercury LEE status based on an initial compliance demonstration. Under the final rule, to qualify for LEE status for pollutants other than Hg, a unit must meet the LEE criteria for a series of performance tests over a 3-year period to demonstrate that the unit continues to perform well below the standard for which the source has obtained LEE status.

G. Continuous Compliance

The most significant changes to the testing and monitoring requirements involve the procedures for demonstrating continuous compliance. The proposed rule contained different options involving CEMS, periodic stack tests, fuel analysis, and various PM and control device operating limits. The final rule greatly simplifies the requirements and provides two basic approaches for most situations: use of continuous monitoring (either CEMS or PM continuous parametric monitoring system, CPMS) or periodic quarterly testing. The final rule does not contain the proposed fuel analysis requirements. For periodic testing, the proposed rule required testing every month or every 2 months. For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil-fired units. The rule requires quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards. The final rule also has a separate compliance demonstration for those liquid oil-fired EGUs that have an annual capacity factor of less than 8 percent (emission limits do not apply, just the tune-up work practice standard). For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil-fired units; quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific parameter monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards.

The continuous monitoring options remain generally intact from the proposed rule, with relatively minor clarifications concerning calculation of 30-boiler operating day averages and QA requirements.

The final rule eliminates all operating limits for PM except for the use of a PM CPMS. For the PM CPMS, the final rule clarifies procedures for setting this operating limit and how it is distinct from the PM emission limit. The PM CPMS will not be correlated as a PM CEMS under PS 11 and will produce data in terms of a signal you define. That signal could be milliamps, stack concentration, or other output signal instead of PM emissions in units of the standard. The operating limit will be set using the highest hourly average obtained from the PM CPMS during the performance test. Compliance with the limit is based on a 30-boiler operating day rolling average basis. However, the final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. The EPA believes that some sources may be interested in adopting this direct approach, and so has included that option in the final rule. If this approach is selected, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11 and Procedure 2. To use this option, the source must elect to meet the filterable PM standard, and not one of the HAP metals standards.

Apart from the operating limit for site-specific monitoring associated with liquid oil-fired EGUs, we removed the other operating limits for control devices based on a review of the comments, after considering other programs in place to ensure proper operations of controls at EGUs. Those other programs include compliance assurance monitoring under part 64, part 70, and New Source Review permit conditions, and other SIP and NSPS requirements for operating and maintaining equipment in accordance with good air pollution control practices. Those requirements, in combination with the CEMS, PM CPMS, and frequent periodic testing provisions under the final rule, will enhance the monitoring of continuous compliance with the requirements of this rule.

Because the EPA is concerned that there will be little or no monitoring in these underlying applicable requirements for acid gases at liquid oil-fired EGUs, the final rule requires a site-specific monitoring plan for those units in this subcategory that demonstrate compliance with the HCl and HF standards through quarterly performance tests. With the exception for limited-use liquid oil-fired EGUs and other monitoring options available (such as fuel moisture monitoring or HCl/HF CEMS), the EPA believes this provision will apply to few units. The owner or operator will submit the site-specific plan to identify appropriate parameters that ensure that the operations of the unit critical to meeting the HCl/HF emission limits remain consistent with conditions during performance testing. This will be approved similarly to an alternative monitoring request. The plan should include the parameters, monitoring approach, QA/QC elements, and data reduction (including averaging period) elements. Like the PM CPMS operating limit, the operating limit for acid gas control devices on liquid oil-fired EGUs will be set using the highest hourly average obtained during the HCl and HF performance tests. Compliance with the limit is based on a 30-boiler operating day rolling average basis.

Finally, we have changed the continuous compliance requirements for the performance tune-up work practice standard since the proposal. Our intent was that this work practice standard could be performed in conjunction with routine maintenance operations at a facility and be a logical extension of routine best practices for boiler inspection and optimization. Based on the comments received, we have reduced the required frequency for this inspection to every 3 years and provided incentives for neural network combustion management and optimization practices by providing a longer interval of 4 years between inspections when such systems are in use at a given EGU.

H. Emissions Averaging

We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for existing EGUs that are located at the same facility that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

As we noted at proposal, part of the EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced is to include emissions averaging. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining a regulation that is workable and enforceable. Emissions averaging would not be applicable to new affected sources and could only be used between EGUs in the same subcategory at a particular facility. Also, owners or operators of existing sources subject to the EGU NSPS (40 CFR part 60, subparts D and Da) would be required to continue to meet the PM emission standard of that NSPS regardless of whether or not they are using emissions averaging (*i.e.,* an EGU subject to 40 CFR part 60, subpart D or Da must meet its applicable NSPS filterable PM emission limit even if it is included in a 40 CFR part 63, subpart UUUUU, emissions averaging group for filterable PM).

Emissions averaging allows owners and operators of a facility that includes existing EGUs within a subcategory to demonstrate that the source complies with the proposed emission limits by averaging the emissions from an individual affected EGU that is emitting above the proposed emission limits with other affected EGUs at the same facility that are emitting below the proposed emission limits and that are within the same subcategory. Although some commenters note that the MACT limits are low, based on the data available to the Agency, we believe that dozens of existing EGUs are achieving all of the limits and, thus, emissions averaging is a possible approach.

The final rule includes an emissions averaging compliance alternative because emissions averaging [315] represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels. We have concluded that averaging in the proposed rule could be implemented and that it would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators. We also recognize that we must ensure that any emissions averaging option can be implemented and enforced, will be clear to sources, and most importantly, will be no less stringent than unit-by-unit implementation of the MACT floor limits.

In the final rule, the EPA is providing that sources may average emissions from existing EGUs at the same facility and within the same subcategory. Further, for Hg emissions only from existing EGUs within the same subcategory, such EGUs in an emissions averaging plan may use an alternate compliance approach consisting of a 90-boiler operating day rolling average emission limit of 1.0 lb/TBtu or 1.1E–2 lb/GWh.

In the memo entitled ''The Impact of Emission Averaging Time on the Stringency of an Emission Standard'' in the docket, we have illustrated why a longer-term average results in a lower limit. In essence, longer-term averages allow particularly high (or low) measurements to be averaged with many more measurements closer to the mean. This results in the highest averages from a longer-term averaging period (*e.g.,* 90 days) being lower than the highest averages in a shorter term averaging period (*e.g.,* 30 days).

We have illustrated this concept by taking Hg CEMS data and calculating rolling 30-day averages and rolling 90-day averages. The 30-day averages have greater variability and, thus, higher peaks and valleys. The 90-day average has less variability; therefore, the same unit is able to meet a tighter 90-day limit.

The EPA is providing this alternate 90-day rolling average compliance approach for Hg only. A 90-day rolling average is appropriate for Hg, and only for Hg, because the health and environmental impacts associated with Hg are related to environmental loading rather than shorter term inhalation or other acute exposure, as is the case with HCl and PM. We believe that this alternative compliance approach will provide at least the same level of environmental protection while allowing companies greater flexibility to use emissions averaging. For example, such an approach would allow for the averaging of an infrequently operated unit that is operating slightly above the standard with a more frequently operated unit that is operating below the standard in the instances when the more frequently operated unit is in a multi-day or multi-week maintenance outage.

The EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging within the same facility across individual existing EGUs subject to the same standards under certain conditions. As mentioned earlier, individual EGUs within an emissions averaging group would be allowed to have emissions greater than, less than, or equivalent with the emissions limit for their subcategory, provided that the average emissions comprised from individual EGU emissions do not exceed the emissions limit for their subcategory. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the same standards in the NESHAP will not be greater under the averaging mechanism than it could be if each individual affected EGU in the subcategory complied separately with the applicable standard. Under this test, the practical outcome of averaging is equivalent to compliance with the MACT floor limits by each discrete EGU, and the statutory requirement that the MACT standard reflect the maximum achievable emissions reductions is, therefore, fully effectuated.

As noted in the proposal preamble, in past rulemakings, the EPA has generally imposed certain limits on the scope and nature of emissions averaging programs. These limits include: (1) No averaging between different types of pollutants; (2) No averaging between sources that are not part of the same affected source; (3) No averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP; and (4) No averaging between existing sources and new sources.

The final rule fully satisfies each of these criteria. First, emissions averaging would only be permitted between individual existing sources at a single stationary source (*i.e.,* the facility), and would only be permitted between individual sources in the same subcategory in the final EGU NESHAP. Further, emissions averaging would not be permitted between two or more different affected sources. Finally, new affected sources could not use emissions averaging. Accordingly, we have concluded that the averaging of emissions across affected units in the same existing source subcategory is consistent with the CAA. In addition, the final rule requires each facility that intends to utilize emissions averaging to develop an emissions averaging plan, which provides additional assurance that the necessary criteria will be followed. In this emissions averaging plan, the facility must include the identification of: (1) All units in the averaging group; (2) the control technology installed; (3) the process parameter that will be monitored; (4) the specific control technology or pollution

[315] As long as required emission rates are designed to account for factors such as changes in averaging times.

prevention measure to be used; (5) the test plan for the measurement of the HAP being averaged; and (6) the operating parameters to be monitored for each control device. A state, local, or tribal regulatory agency that is delegated authority for this rule could require the emissions averaging plan to be submitted or even approved before emissions averaging could be used. Upon receipt, the regulatory authority would not be able to approve an emissions averaging plan differing from the eligibility criteria contained in the rule.

The final rule excludes new affected sources from the emissions averaging provision. The EPA does not believe the statute authorizes emissions averaging for new affected sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion.

With the monitoring and compliance provisions that are being finalized, there is additional assurance that the environmental benefit will be realized. Further, the emissions averaging provision would not apply to individual EGUs if the EGU shares a common stack with units in other subcategories, because in that circumstance it is not possible to distinguish the emissions from each individual unit.[316]

The rule allows EGUs that rely on CEMS for compliance demonstrations to be able to participate in emissions averaging and the emissions limits are not subject to a discount. The EPA believes that the data certainty provided by units that use CEMS would be ideal for emissions averaging and the flexibility and cost-effectiveness it offers. Given the homogeneity of fuels within the rules subcategories, along with other emissions averaging criteria, the Agency believes use of a discount factor to be unwarranted for this rule.

The emissions averaging provisions in this final rule are based in part on the emissions averaging provisions in the Hazardous Organic NESHAP (HON). The legal basis and rationale for the HON emissions averaging provisions were provided in the preamble to the final HON.[317] We do not believe that we have the authority to provide for emissions averaging among EGUs in different subcategories or among EGUs not physically located at the same affected facility.

I. Notification, Recordkeeping, and Reporting

Compared to the proposed rule, the reduced continuous compliance requirements in the final rule—primarily reduced testing frequencies and removal of fuel analyses and control device or fuel operating parameter monitoring—considerably reduces the overall burden associated with recordkeeping and reporting. Based on evaluation of the comments received, we have established a provision in the final rule for submission of most CEMS data (including monitoring plan, emissions data, and QA data) through ECMPS, so that the affected industry uses a common reporting tool for submitting CEMS data.

For data other than most CEMS data, the final rule requires electronic reporting of certain data, including performance test reports, PM CPMS data, PM CEMS data, and, if approved as part of an alternative monitoring request, HAP metals CEMS data. Other reports, such as notifications, must be submitted in hard copy format or in accordance with the procedures established by state and local agencies that receive delegation for implementing this rule. In the proposed rule, we took comment on these approaches and stated our anticipation of adopting these approaches. In the final rule, we have extended the ECMPS reporting to most CEMS data to promote harmonization for CEMS data from the industry, while leaving reporting of non-CEMS data in a separate reporting system.

J. Technical/Editorial Corrections

In this final action, we are making a number of technical corrections and clarifications to 40 CFR part 63, subpart UUUUU. These changes clarify procedures for implementing the emission limitations for affected sources. We are also clarifying several definitions to help affected sources determine applicability of this rule. We have modified some proposed regulatory language based on public comments. In addition, in response to comments received (including the May 2010 notice from the Utility Air Regulatory Group (UARG) of calculation errors in the proposed Hg MACT floor limits), we have checked all calculations and made corrections where necessary.

In several places throughout the subpart, including the associated tables, we have corrected the cross-references to other sections and paragraphs of the subpart.

VII. Public Comments and Responses to the Proposed NESHAP

A. MACT Floor Analysis

1. New Data/Technical Corrections to Old Data

Comment: Many commenters identified errors in the emissions database compiled through information provided by industry in response to the 2010 information collection request (ICR) that supported development of this rule. Commenters submitted corrections to the EPA during the public comment period.

Response: The EPA has incorporated technical corrections and new data submitted prior to the end of the comment period. The corrections and new data are described in detail in a memorandum in the docket. The EPA re-ranked the sources in the MACT floor pools to the extent necessary based on the new or corrected data, and we recalculated the MACT floors as necessary based on the re-ranking of sources. The revised MACT floors were established using the same methodology set forth in the proposed rule.

2. Pollutant-by-Pollutant Approach

Comment: Many commenters raised concerns about the way the EPA determined the MACT floors using a pollutant-by-pollutant approach. Commenters contended that such a methodology produced limits that are not achievable in combination, and as such, the limits do not comport with the intent of the statute or the recent court decision (*NRDC* v. *EPA,* 2007). Commenters further added that the CAA directs the EPA to set standards based on the overall performance of ''sources'' and CAA sections 112(d)(1), (2), and (3) specify that emissions standards be established on the ''in practice'' performance of a ''source'' in the category or subcategory. Commenters stated that if Congress had intended for the EPA to establish MACT floor levels considering the achievable emission limits of individual HAP, it could have worded CAA section 112(d)(3) to refer to the best-performing sources ''for each pollutant.'' Many commenters added that the EPA's discretion in setting standards is limited to distinguishing among classes, types, and sizes of sources. Commenters contend that although Congress limited the EPA's authority to parse units and sources with similar design and types, it does not allow the EPA to ''distinguish'' units and sources by individual pollutant as proposed in this rule (*Sierra Club* v. *EPA,* 551 F.3d 1019, 1028 (D.C. Cir. 2008)). By calculating each MACT floor

[316] The EPA has reviewed monitoring data submitted to the Agency under the Title IV Acid Rain Program. Based on that review, the EPA is unaware of any coal- and oil-fired units that share a common stack.

[317] Hazardous Organic NESHAP (59 FR 19,425; April 22, 1994).

independently of the other pollutants, commenters contend that the combination of HAP limits results in a set of standards that only a hypothetical ''best performing'' unit could achieve.

Response: We disagree with the commenters who believe MACT floors cannot be set on a pollutant-by pollutant basis. Contrary to the commenters' suggestion, CAA section 112(d)(3) does not mandate a total facility approach. A reasonable interpretation of CAA section 112(d)(3) is that MACT floors may be established on a HAP-by-HAP basis, so that there can be different pools of best performers for each HAP. Indeed, as illustrated below, the total facility approach not only is not compelled by the statutory language but can lead to results so arbitrary that the approach may simply not be legally permissible.

Clean Air Act section 112(d)(3) is not explicit as to whether the MACT floor is to be based on the performance of an entire source or on the performance achieved in controlling particular HAP. Congress specified in CAA section 112(d)(3) the minimum level of emission reduction that could satisfy the requirement to adopt MACT. For new sources, this floor level is to be ''the emission control that is achieved in practice by the best controlled similar source.'' For existing sources, the floor level is to be ''the average emission limitation achieved by the best performing 12 percent of the existing sources'' for categories and subcategories with 30 or more sources, or ''the average emission limitation achieved by the best performing 5 sources'' for categories and subcategories with fewer than 30 sources. Commenters point to the statute's reference to the best performing ''sources,'' and claim that Congress would have specifically referred to the best performing sources ''for each pollutant'' if it intended for the EPA to establish MACT floors separately for each HAP.

The EPA disagrees. The language of the Act does not address whether floor levels can be established HAP-by-HAP or by any other means. The reference to ''sources'' does not lead to the assumption the commenters make that the best performing sources can only be the best-performing sources for the entire suite of regulated HAP. Instead, the language can be reasonably interpreted as referring to the source as a whole or to performance as to a particular HAP. Similarly, the reference in the new source MACT floor provision to ''emission control achieved by the best controlled similar source'' can mean emission control as to a particular HAP or emission control achieved by a source as a whole.

Commenters also stressed that CAA section 112(d) requires that floors be based on actual performance from real facilities. The EPA agrees that this language refers to sources' actual operation, but again the language says nothing about whether it is referring to performance as to individual HAP or to single facility's performance for all HAP. Industry commenters also said that Congress could have mandated a HAP-by-HAP result by using the phrase ''for each HAP'' at appropriate points in CAA section 112(d). The fact that Congress did not do so does not compel any inference that Congress was *sub-silentio* mandating a different result when it left the provision ambiguous on this issue. The argument that MACT floors set HAP-by-HAP are based on the performance of a hypothetical facility, so that the limitations are not based on those achieved in practice, just reiterates the question of whether CAA section 112(d)(3) refers to whole facilities or individual HAP. All of the limitations in the floors in this rule reflect sources' actual performance and were achieved in practice. As to commenters' claims that standards set in this manner cannot be met by any actual sources, we have determined that there are approximately 69 existing coal-fired EGUs that meet all of the final existing source MACT emission limits (out of 252 EGUs that reported data for Hg, PM, and HCl in the 2010 ICR) and at least one EGU that meets all of the final new source MACT emission limits.

Commenters also point to the EPA's subcategorization authority, and claim that because Congress authorized the EPA to distinguish among classes, types, and sizes of units, the EPA cannot distinguish units by individual pollutant, as they allege the EPA did in the proposed rule. However, that statutory language addresses the EPA's authority to subcategorize sources within a source category prior to setting standards, which the EPA has done for certain EGUs. The EPA is not distinguishing within each subcategory based on HAP emitted. Rather, it is establishing emissions standards based on the emissions limits achieved by units in each subcategory. Therefore, the EPA's subcategorization authority is irrelevant to the question of how the EPA establishes MACT floor standards once it has made the decision to distinguish among sources and create subcategories.

The EPA's long-standing interpretation of the Act is that the existing and new source MACT floors are to be established on a HAP-by-HAP basis. One reason for this interpretation is that a whole plant approach could yield least common denominator floors—that is, floors reflecting limited or no control, rather than performance which is the average of what best performers have achieved. *See* 61 FR 173687 (April 19, 1996); 62 FR 48363–64 (September 15, 1997) (same approach adopted under the very similar language of CAA section 129(a)(2)). Such an approach would allow the performance of sources that are outside of the best-performing 12 percent for certain pollutants to be included in the floor calculations for those same pollutants, and it is even conceivable that the worst performing source for a pollutant could be considered a best performer overall, a result Congress could not have intended. Inclusion of units that are outside of the best performing 12 percent for particular pollutants would lead to emission limits that do not meet the requirements of the statute.

For example, if the best performing 12 percent of facilities for HAP metals were also the worst performing units for acid gas HAP and the best performers for acid gas HAP were the worst performers for HAP metals, the floor for acid gases or metals would end up not reflecting best performance. In such a situation, the EPA would have to make a value judgment as to which pollutant reductions were most critical to decide which sources are best controlled.[318] Such value judgments are antithetical to the direction of the statute at the MACT floor-setting stage.

Commenters suggested that a multi-pollutant approach could be implemented by weighting pollutants according to relative toxicity and calculating weighted emissions totals to use as a basis for identifying and ranking best performers. This suggested approach would require the EPA to essentially prioritize the regulated HAP based on relative risk to human health of each pollutant, where risk is a criterion that has no place in the establishment of MACT floors, which are required by statute to be based on technology.

The central purpose of the amended air toxics provisions was to apply strict technology-based emission controls on HAP. *See, e.g.,* H. Rep. No. 952, 101st Cong. 2d sess. 338. An interpretation that the floor level of control must be limited by the performance of devices

[318] See Petitioners Brief in *Medical Waste Institute et al.* v. *EPA,* No. 09–1297 (D.C. Cir.) pointing out, in this context, that ''the best performers for some pollutants are the worst performers for others'' (p. 34) and ''[s]ome of the best performers for certain pollutants are among the worst performers for others.''

that only control some of these pollutants effectively guts the standards by including worse performers in the averaging process, whereas the EPA's interpretation promotes the evident Congressional objective of having the floor reflect the average performance of best performing sources. Because Congress has not spoken to the precise question at issue, and the Agency's interpretation effectuates statutory goals and policies in a reasonable manner, its interpretation must be upheld. *See Chevron* v. *NRDC,* 467 U.S. 837 (1984).[319]

The EPA notes, however, that if optimized performance for different HAP is not technologically possible due to mutually inconsistent control technologies (for example, if metals performance decreased as organics reduction is optimized), then this would have to be taken into account by the EPA in establishing a floor (or floors). The Senate Report indicates that if certain types of otherwise needed controls are mutually exclusive, the EPA is to optimize the part of the standard providing the most environmental protection. S. Rep. No. 228, 101st Cong. 1st sess. 168 (although, as noted, the bill accompanying this Report contained no floor provisions). It should be emphasized, however, that the D.C. Circuit has stated that ''the fact that no plant has been shown to be able to meet all of the limitations does not demonstrate that all the limitations are not achievable.'' *Chemical Manufacturers Association* v. *EPA,* 885 F. 2d at 264 (upholding technology-based standards based on best performance for each pollutant by different plants, where at least one plant met each of the limitations but no single plant met all of them).

All available data for EGUs indicate that there is no technical problem achieving the floor levels contained in this final rule for each HAP simultaneously, using the MACT floor technology. Data demonstrating a technical conflict in meeting all of the limits have not been provided, and, as stated above, based on the available data, there are approximately 64 EGUs that meet all of the final existing source emission limits and at least one EGU that meets all of the final new source emission limits.

[319] Because industry commenters argued that the statute can only be read to allow floors to be determined on a single source basis, commenters offered no view of why their reading could be viewed as reasonable in light of the statute's goals and objectives. It is not evident how any statutory goal is promoted by an interpretation that allows floors to be determined in a manner likely to result in floors reflecting emissions from worst or mediocre performers.

3. Minimum Number of EGUs To Set Floors

Comment: Many commenters indicated that CAA section 112 requires that data from a minimum of 5 units are required to set MACT floors for existing sources. Commenters noted that the EPA's use of less than 5 units for subcategories with greater than 30 units is a legalistic reading of CAA section 112 that could result in such absurd results as using 5 units to set MACT floors for a subcategory with 29 units and data for only 10 units, but using a single unit to set MACT floors for a subcategory with 31 units and data for only 10 units.

Response: The EPA does not agree that CAA section 112(d)(3) mandates a minimum of 5 sources in all instances, notwithstanding the incongruity of having less data to establish floors for larger source categories than is mandated for smaller ones. The literal language of the provision appears to compel this result. CAA section 112(d)(3) states that for categories and subcategories with at least 30 sources, the MACT floor for existing sources shall be no less stringent than the average emission limitation achieved by the best-performing 12 percent of the sources for which the Administrator has emissions information. The plain language of this provision requires the use of fewer data points for large source categories than for small source categories where the Administrator only has emissions information on a small number of units for categories and subcategories with 30 or more sources. Furthermore, commenters contend that Congress could not have intended the floors for a subcategory with 29 sources to be based on 5 sources and a subcategory with 31 sources to be based on less than that number; but we maintain this contention is without merit because 12 percent of 31 is 3.72 (rounded to 4) so the EPA would not base standards for a subcategory with 31 sources on 5 sources even if we had data on all 31 sources in the subcategory. For these reasons, we decline to adopt commenters' position and continue to adhere to the clear statutory directive.

4. Treatment of Detection Levels

Comment: Commenters stated that when setting the MACT floors, non-detect values are present in many of the datasets from best performing units. Commenters provided input on how these non-detect values should be treated in the MACT floor analysis. Some commenters agreed that it is appropriate to keep the detection levels as reported, while certain commenters suggested that the detection levels should be replaced using a value of half the method detection limit (MDL). Many other commenters stated that data that are below the detection limit should not be used in setting the floors, and these data should be replaced with a higher value including either the MDL, limit of quantitation (LOQ), practical quantitation limit (PQL), or reporting limit (RL) for the purposes of the MACT floor calculations. Other commenters stated all non-detect values should be excluded from the floor analysis, or all values should be treated as zero.

Some commenters stated it is necessary to keep the data as reported because changing values would lead to an upward bias. Additional commenters agreed with this basic premise, but suggested that replacing non-detect data with a value of half the MDL is appropriate while still minimizing the bias. They noted that treating measurements below the MDL as occurring at the MDL is statistically incorrect and violates the statute's ''shall not be less stringent than'' requirement for MACT floors. One commenter also provided a reference for a statistical method based on a log-normal distribution of the data which estimated the ''maximum likelihood'' of data values; this result is slightly higher than half the MDL.

Some commenters stated that it is necessary to substitute the MDL value when performing the MACT floor calculations. With MDL defined as the lowest concentration that can be distinguished from the blank at a defined level of statistical significance, this is an appropriate value. If MDL values are not reported, one commenter suggested an approach for estimating an MDL equivalent value, but recognized that the background laboratory and test report files may not be available to the EPA in order to derive these estimates.

Most commenters representing industry and industry trade groups argued that either LOQ or PQL values should replace non-detects. The LOQ is defined as the smallest concentration of the analyte which can be measured. These commenters contended that the LOQ leads to a quantifiable amount of the substance with an acceptable level of uncertainty. A few commenters provided calculations showing some of the proposed MACT floors were below the LOQ. Additionally, some of these commenters stated that using LOQ or PQL values also incorporates additional sources of random and inherent sampling error throughout the testing process, which is necessary. These errors occur during sample collection, sample recovery, and sample analysis;

MDL values only account for method specific (*e.g.,* instrument) errors. These commenters contended that the three times the MDL approach discussed in the proposal accounts for some measurement errors but does not account for these unavoidable sampling errors. The commenters also noted that an LOQ is calculated as 3.18 times the MDL, and PQL is calculated as 5 to 10 times the MDL. Many of the commenters in support of using either an LOQ or PQL value ultimately believed a work practice is more appropriate where a MACT floor limit is below either of these two values. They cited CAA section 112(h)(1) which allows work practices under CAA section 112(h)(2) if ''the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations''. These commenters stated that the inability of sources to accurately measure a pollutant at the level of the MACT floor qualifies as such a technological limitation that warrants a work practice standard.

Commenters stated that where the proposed MACT floor is below the LOQ or PQL then that source category has a technological measurement limitation. A few commenters suggested RL values should be used when developing the floor limits. They stated that the RL is the lowest level at which the entire analytical system gives reliable signals and includes an acceptable calibration point. They added that use of an acceptable calibration point is critical in showing that numbers are real versus multiplying the MDL by various factors.

Several commenters stated that all non-detect values should be excluded from MACT floor calculations. They believed that excluding all non-detect values would eliminate any potential errors or accuracy issues related to testing for compliance. Due to inconsistencies of the MDL value reported for non-detect data, one commenter suggested treating all such values as zero. This would provide a consistent approach for setting the floor as well as determining compliance.

Several commenters provided input on the EPA's proposed method of three times the MDL as an option for setting limits. A few commenters in support noted that this approach provided a reasonable method to account for data variability as it took into account more than just analytical instrument precision. Many other commenters argued that this method results in limits which are too low, namely that it is still lower than the LOQ value which they are in favor of as a substitute for any reported non-detect data. Other commenters disagreed with this method and claimed that it would lead to results which introduce a high bias in the floor setting process. A few contended that multiplying by 3 would introduce a 300 percent error into the floor, resulting in a floor that is less stringent than required by the Act. Others suggested that the MDL values are antiquated and already too high and thus it is not appropriate to multiply them by three. Also, a few commenters suggested multiplying the MDL by three would not reflect the actual lower emissions achieved by any source and as such is unlawful under CAA section 112(d).

Response: We agree with many of the comments related to treatment of data reported as detection limit values in the development of MACT floors and emissions limits. As we noted at proposal, the statistical probability procedures applied in calculating the floor or an emissions limit inherently and reasonably account for emissions data variability including measurement imprecision when the database represents multiple tests from multiple emissions units for which all of the data are measured significantly above the method detection level. That is less true when the database includes emissions occurring below method detection capabilities regardless of how those data are reported.

The EPA's guidance to respondents for reporting pollutant emissions used to support the data collection specified the criteria for determining test-specific method detection levels. Those criteria ensure that there is only about a 1 percent probability of an error in deciding that the pollutant measured at the method detection level is present when in fact it was absent. (Reference: ReMAP: PHASE 1, Precision of Manual Stack Emission Measurements; American Society of Mechanical Engineers, Research Committee on Industrial and Municipal Waste, February 2001.) Such a probability is also called a false positive or the alpha, Type I, error. This means specifically that for a normally distributed set of measurement data, 99 out of 100 single measurements will fall within $\pm 2.54 \times$ standard deviation of the true concentration. The anticipated range for the average of repeated measurements comes progressively closer to the true concentration. More precisely, the anticipated range varies inversely with the square root of the number of measurements. Thus, for a known standard deviation (SD) of anticipated single measurements, the anticipated range for 99 out of 100 future triplicate measurements will fall within ± 2.54 SD/$\sqrt{3}$ of the true concentration. This relationship translates to an expected measurement imprecision for an emissions value occurring at or near the method detection level of about 40 to 50 percent.

By assuming a similar distribution of measurements across a range of values and increasing the mean value to a representative higher value (*e.g.,* 3 times minimum detection level or 3xMDL), we can estimate measurement imprecision at other levels. For an assumed 3xMDL, the estimated measurement imprecision for a three test run average value would be on the order 10 to 20 percent. This is about the same measurement imprecision as found for Methods 23 and 29 indicated in the ASME ReMAP study for the sample volumes prescribed in the final rule (*e.g.,* 4 to 6 dscm) for multiple tests.

Analytical laboratories often report a value above the method detection limit that represents the laboratory's perceived confidence in the quality of the value. This independently adjusted value is expressed differently by various laboratories and is called LOQ, PQL, or RL. In many cases, the LOQ, PQL, or RL is simply a multiplication of the method detection limit. Commonly used multipliers range from 3 to 10. Because these values reflect individual laboratories' perceived confidence, and, therefore, could be viewed as arbitrary, we decline to adopt the LOQ, PQL, or RL because such approaches in our view would inappropriately inflate the MACT floor standards. Our alternative to those inconsistent approaches is discussed below.

Consistent with findings expressed in reports of emissions measurement imprecision and the practices of analytical laboratories, we believe that using a measurement value of 3 times a representative method detection limit established in a manner that assures 99 percent confidence of a measurement above zero will produce a representative method reporting limit suitable for establishing regulatory floor values.

On the other hand, we also agree with commenters that an emissions limit set from a small subset of data or data from a single source may be significantly different than the actual method detection levels achieved by the best performing units in practice. This fact, combined with the low levels of emissions measured from many of the best performing units, led the EPA since proposal to review and revise the procedure intended to account for the contribution of measurement imprecision to data variability in establishing effective emissions limits. In response to the comments about the quality of measurements at very low emissions limits especially for new sources, we revised the procedure for identifying a representative method detection level (RDL).

The revised procedure for determining an RDL starts with identifying all of the available reported pollutant-specific method detection levels for the best performing units regardless of any subcategory (*e.g.,* existing or new, fuel type, etc.). From that combined pool of data, we calculate the arithmetic mean value. By limiting the data set to those tests used to establish the floor or emissions limit (*i.e.,* best performers), which in this case is a larger data set than normally available for establishing NESHAP, we believe that the result is representative of the best performing testing companies and laboratories using the most sensitive analytical procedures. We believe that the outcome should minimize the effect of a test(s) with an inordinately high method detection level (*e.g.,* the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the minimum value for reporting was other than the detection level). We then call the resulting mean of the method detection levels the representative detection level (RDL) because it is characteristic of accepted source emissions measurement performance.

The second step in the process is to calculate 3xRDL to compare with the calculated floor or emissions limit. This step is similar to what we have used for other NESHAP including the Portland Cement rule. As outlined above, we use the multiplication factor of 3 to reduce the imprecision of the analytical method until the imprecision in the field sampling reflects the relative method precision as estimated by the ASME ReMAP study. That study indicates that such relative imprecision remains a constant 10 to 20 percent over the range of the method. For assessing the calculated floor results relative to measurement method capabilities, if 3xRDL were less than the calculated floor or emissions limit (*e.g.,* calculated from the upper predictive limit, UPL), we would conclude that measurement variability was adequately addressed with the initial floor calculation. The calculated floor or emissions limit would need no adjustment. If, on the other hand, the value equal to 3xRDL were greater than the UPL, we would conclude that the calculated floor or emissions limit did not account entirely for measurement variability. Where such was the case, we substituted the value equal to 3xRDL for the calculated floor or emissions limit (UPL) which results in a concentration where the method would produce measurement accuracy on the order of 10 to 20 percent similar to other EPA test methods and the results found in the ASME ReMAP study.

We determined the RDL for each pollutant using data from tests of all the best performers for all of the final regulatory subcategories (*i.e.,* pooled test data). We applied the same pollutant-specific RDL and emissions limit assessment and adjustment procedures to all subcategories for which we established emissions limits. We believe that adjusting emissions limits in this manner, which ensures that measurement variability is adequately addressed relative to compliance determinations, is a better procedure than the one applied at proposal, which was based on more limited data. We also believe that currently available emissions testing procedures and technologies provide the measurement certainty sufficient for sources to demonstrate compliance at the levels of the revised emissions limits.

5. Basis for New Source MACT

Comment: Several commenters stated that the proposed limits set for new EGUs do not represent the best performing EGU. The commenters state that the EPA has chosen the strictest limit irrespective of the EGU and that limits for new EGUs should be achievable. According to the commenters, no existing EGU is currently meeting the proposed limits, which will result in a moratorium on the construction of new coal-fired EGUs. Further, commenters state that another result of the EPA's flawed approach is that the proposed standards for new EGUs are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters assert that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure which will, in turn, effectively preclude the construction of any new coal-based EGUs.

Commenters also stated that the EPA failed to address cumulative effects of using multiple pollution control devices in determining MACT levels applicable to PM levels. In proposing total PM as a surrogate, commenters believe that the EPA failed to consider or address the antagonistic effects that adding multiple pollution control devices can have on an EGU's HAP emissions. Commenters indicated that EGUs would not be able to comply with the proposed new source HCl limit without adding a scrubber or some type of sorbent injection to control HCl emissions. Adding these HCl control technologies will increase the total PM emissions of these units. According to commenters, because a fabric filter-alone configuration (the basis for the new source PM limit) would not meet all MACT limits, these units may not be the best-performing units.

Response: The EPA disagrees with the commenters' statements that no existing unit is currently meeting the new source limits. The EPA established the new source limits based on data from existing EGUs and there is at least one EGU, based on the data available, that is meeting all three final HAP limits and at least eight EGUs that are meeting one or more of the new source limits. As a result of comments received on the full body of data, the EPA has re-ranked the best performing EGUs and reviewed the new source limits based on the re-ranking where appropriate. Based on the revised ranking, the best performing source for PM has changed and that source now forms the basis for the new source filterable PM limit in the final rule. The source is a coal-fired EGU that includes the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively (*i.e.,* it is a unit with SCR, dry FGD, and FF). Thus, the commenters' concerns are no longer relevant as they relate to PM emissions from coal-fired EGUs.

The EPA also believes that the EGUs serving as the basis for the new source Hg and HCl limits in the final rule are representative of what a new coal-fired EGU would look like to meet all of the requisite regulations applicable to EGUs (*e.g.,* NSPS and the CSAPR) as they also include the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively. The EPA has also taken into account the ability of the various test methods to accurately measure emissions at the levels being demonstrated by the EGUs in the top performing 12 percent in establishing the final limits, and we have determined that there are adequate test methods to measure the regulated HAP at the new source levels.

6. Achievability of Limits

Comment: A number of commenters state that the EPA has chosen the strictest limit irrespective of the unit and that limits for new EGUs should be achievable. According to the commenters, no existing unit is currently meeting the proposed new source limits, which will result in a moratorium on the construction of new coal-fired units. The commenters state that this regulation goes beyond protecting public health and will impact the country's choice of fuel for energy production. Other commenters state that another result of the EPA's flawed approach is that the proposed standards for new units are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters allege that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure, and that this in turn will effectively preclude the construction of any new coal-based units. Commenters maintain that adopting standards effectively banning new coal units amounts to a momentous change in national energy policy without discussion or analysis and far exceeds the EPA's authority.

Some commenters add that the proposed new source MACT standards do not represent rates that have been achieved in practice and are orders of magnitude lower than any of the CAA section 112(g) case-by-case MACT limits established for the most advanced units in the U.S. coal fleet by multiple state agencies.

Other commenters stated that the synergistic impact of multiple controls has not been taken into account in the proposed rules. Commenters argue that circumstances exist with respect to the control of acid gases, which will require scrubbers or other SO_2 controls that add particulate to the flue gas stream, and that added particulate must be removed by PM control devices along with the particulate added to the flue gas for EGUs that need to install ACI for Hg control. Because particulate devices provide a fixed percent reduction of particulate, commenters assert that it is mathematically certain that PM performance will decrease because control of both acid gases and Hg would add PM to the flue gas stream which would in turn decrease performance of the PM control on the relevant mass metric. As a consequence, commenters allege that there is no assurance that sources can meet the EPA's ''cherry-picked'' floors for acid gases and for Hg by ''optimizing'' these systems to meet the performance of the floor units because to do so would impact their ability to meet the EPA's similarly ''cherry-picked'' total PM floor standard.

The commenters state that, for existing sources as with the new source standard-setting approach, a pollutant-by-pollutant approach does not consider what the top performing 12 percent achieve in practice for all pollutants and does not consider the antagonistic effects of the concurrent use of various control technologies. For example, one commenter states that 47 of the 131 sources used to calculate the existing source total PM limit only had PM control but no acid gas or Hg controls that could emit additional PM. According to the commenter, the CAA is clear that standards must be based on actual sources and not the product of a pollutant-by-pollutant determination resulting in a set of composite standards that do not necessarily reflect the overall performance of any actual source. To address these issues, the commenter recommends that the EPA use an approach that more accurately reflects what actual best performing sources achieve.

Response: The EPA disagrees with the commenters' contention that the pollutant-by-pollutant approach to establishing MACT floors is inconsistent with the CAA for the reasons set forth in the response to comments on the EPA's MACT floor setting process. In addition, the EPA established the proposed new source limits based on data from existing EGUs, and there are EGUs that are able to meet the new source limits. To the extent the commenters are concerned that no existing source is simultaneously meeting all of the new sources limits, we note that the EPA has revised the new source standards based on comments and data corrections that industry made to data it incorrectly provided in response to the utility ICR. We have identified at least one source that is meeting all of the new source MACT limits in the final rule.

We disagree with commenters that suggest the proposed new source standards are invalid because they are more stringent than CAA section 112(g) case-by-case MACT limits established by state agencies. As commenters note, states, not the EPA, established the CAA section 112(g) standards, and they did so based on the information available to them. The EPA likewise must establish CAA section 112(d) standards based on the available data. We have considered the available data and information, including the 2010 ICR data, and complied with the requirements of CAA section 112(d) in establishing the standards in this final rule. That the final standards are more stringent than CAA section 112(g) standards issued by certain state agencies has no bearing on the legitimacy of the standards at issue here.

The EPA agrees with commenters that the SO_2 and some Hg controls may add to the PM loading and that it is reasonable to establish the new source standard based on an EGU that has a suite of controls that will be required of any new source. For example, new coal-fired EGUs will be required to comply with the utility NSPS and may have to comply with the CSAPR and other requirements (*e.g.,* SIP or state-only requirements). Commenters are also correct that the proposed new source PM surrogate standard was based on a source that is not like a coal-fired EGU that would be constructed today (*i.e.,* an EGU with only PM control and no SO_2 controls).

The final standard is not based on the source used to establish the proposed limit. As stated above, industry commenters provided data corrections and new data and the EPA considered that new and revised data in establishing the final standards. We re-ranked all the coal-fired EGUs based on the new data. The new ranking of coal-fired EGUs resulted in a change of the source we used to establish the new source PM surrogate standard for non-mercury metal HAP. The basis for the new source limit in the final rule is a unit that has a full suite of controls similar to what would be required for any new coal-fired EGUs (*i.e.,* it is a unit with SCR, dry FGD, and FF). The EPA has identified at least one EGU meeting all of the final new source limits; thus, the EPA does not believe that it is finalizing standards that ''ban'' new coal-fired generation as indicated by the commenter.

The EPA also disagrees that the final new source standards are so stringent that there are not adequate test methods available to determine compliance with the standards. The EPA has taken into account the ability of the various test methods to accurately measure emissions at the levels being demonstrated by the best performing EGUs in establishing the final limits. This has been done through use of the 3XRDL (discussed elsewhere in this preamble and the Response to Comments document) and through adjustments to the sampling time requirements for certain of the HAP.

7. Comments on Technical Approaches

Comment: Commenters disagreed with the EPA's use of data from multiple units exhausting through a common stack and argued that the EPA unreasonably treated data from multiple units exhausting through a single stack as multiple data points in establishing the MACT floors. The commenters believe it is improper to count a single data point from a multiple-unit common stack as multiple data points. The commenters state that where two units exhaust through a common stack, the performance is not that of two sources, but only one. The commenters indicate that emissions performance that is actually achieved reflects combined operation, which cannot rationally be split into two parts (data points) because this emissions performance was not achieved by two separate sources. Commenters assert that although it may be acceptable for the EPA to surmise that the combined performance of multiple EGUs and pollution control devices represents an emissions control strategy that could be a best performer, thereby entitling the Agency to use the data at all, the fact is there is only one performer not two. Commenters contend that apart from being inconsistent with applicable MACT case law, counting combined stack emissions as two or more data points is unreasonable because it dampens variability and over-represents the emissions data by creating multiple ''performers'' or sources when there is in fact only one. Commenters note that in the major-source Industrial Boiler NESHAP, the EPA argued its approach of creating two data points from a single combined stack data point is reasonable because it cannot separate the comingled fraction of the emissions from the different emission points. Commenters state that this is irrelevant, believing that there is no basis to separate these emissions because the MACT floor is based on best performing sources and there is only a single source.

According to commenters, the EPA cannot determine what amount of the overall performance of a combined stack data point is the specific result of the combination. Commenters assert that the EPA also argues that applying the emissions equally to multiple units exhausting through a single stack ''accurately represents the emissions of those units on average.'' Commenters believe that is simply not correct and there is no plausible factual basis for that statement, believing that there is no unit that ''achieved'' those emissions. Rather, the data represent the combined weighted average of two units, without knowing how either unit actually performed. One commenter also stated that in several instances when a facility operated tandem or multiple EGUs but only submitted a single stack measurement, the EPA used the single stack measurement to represent Hg emissions from the facility's other stacks.

Response: The EPA disagrees with commenters. As in the major-source Industrial Boiler NESHAP, the EPA continues to believe that the emissions from the common stack represent the average emissions of the EGUs exhausting to the common stack and are representative of both EGUs. Commenters have provided no data to support the contention that this assumption is false. In addition, commenters' contention that distinct EGUs (*i.e.,* boilers) are one source if they emit out of a common stack is not consistent with the CAA section 112(a)(8) definition, which clearly applies to the individual boiler units with a capacity of more than 25 MW. It would not be reasonable in light of that definition to consider the emissions from two boilers to a common stack as the emissions of one EGU. The EPA only used data from combined stacks where both EGUs were operating or where the owner/operator certified that no air leakage could occur. The EPA expects that companies will comply with the final rule by conducting testing at the common stack as that is usually where the sampling locations are (rather than in the intermediate ductwork) and will report the results as being for each EGU.

The EPA has reviewed the data based on comments received and does not believe that there are any inconsistencies in the data set used for the final rule. In the MACT floor analysis, the EPA only used data from stacks that were tested or for which test data were provided. These stack measurements were not used to represent emissions from other, non-tested, stacks in the MACT analysis.

8. Alternative Units for Emission Limits

Comment: Several commenters submitted a variety of alternatives to the input- or output-based MACT floor limits as means of establishing the MACT floors. Some commenters suggested emission reductions or removal efficiencies. These commenters suggest that a percent reduction MACT metric be considered as an alternative, and not a substitute, to some of the proposed MACT numerical limits, particularly those that appear too problematic to meet in reality. A necessary data format and protocol could be developed for some HAP, such as Hg, that would allow an appropriate percent reduction alternative to be developed. Commenters believe that the Brick MACT decision stands for the proposition that a MACT level cannot be based on a specific technology; commenters are advocating that a percent reduction format would specify the level or reduction but would not dictate any specific control or methodology.

Comments were also received that some state programs contain Hg emission limits that are more stringent than the EPA's proposed emission limits. The programs of Connecticut, Massachusetts, New Hampshire, New Jersey, and New York were noted. Commenters provided information on these states' Hg emission limits, which often are in the form of either a lb/TBtu format or a percent reduction. Commenters noted that EGUs in these states were in compliance with the state regulations and, therefore, the EPA's emission limits should be more stringent.

Response: The EPA disagrees with the commenters' suggestion that a percent reduction standard should be included in the final rule. The EPA notes that the inability to account for Hg removed from the coal prior to combustion was not the only reason provided for not using a percent reduction format. As noted in the proposal preamble (76 FR 25040), we did consider using a percent reduction format for Hg. We determined not to propose a percent reduction standard for several reasons. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's desire to promote, and give credit for, coal preparation practices that remove Hg and other HAP before firing because we did not have the data to account for those practices. Specifically, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s). Such an approach would be difficult to implement and enforce. Moreover, we do not have the data necessary to establish percent reduction standards for HAP at this time. Depending on what was considered to be the ''inlet'' and the degree to which precombustion removal of HAP was desired to be included in the calculation, the EPA would need (*e.g.*) the HAP content of the coal as it left the mine face, as it entered the coal preparation facility, as it left the coal preparation facility, as it entered the EGU, as it entered the control devices, and as it left the stack to be able to establish percent reduction standards. We do not have this type of information.

The EPA believes that an emission rate format allows for, and promotes, the use of pre-combustion HAP removal processes because such practices will help sources assure they will comply with the proposed standard. A percent reduction requirement would likely limit the flexibility of the regulated community by requiring the use of a control device. In addition, as discussed in the Portland Cement NESHAP (75 FR 55002; September 9, 2010), the EPA believes that a percent reduction format negates the contribution of HAP inputs to EGU performance and, thus, may be inconsistent with the D.C. Circuit's rulings as restated in the *Brick* case (479 F.3d at 880) which say, in effect, that it is the emissions achieved in practice (*i.e.,* emissions to the atmosphere) that matter, not how one achieves those emissions.

The 2010 ICR data confirm that plant inputs likely play a role in emissions to the atmosphere. These data indicate that some EGUs are achieving lower Hg emissions to the atmosphere at a lower Hg percent reduction (*e.g.,* 75 to 85 percent) than are other EGUs with higher percent reductions (*e.g.,* 90 percent or greater). However, we are not sure whether these data accurately reflect the total percent reduction mine-to-stack because we do not have all the data necessary to make that determination. Thus, we proposed to establish numerical emission standards for Hg HAP emissions from EGUs and we are finalizing numerical emission standards. The same issues prevent us from considering percent reduction standards for the other HAP emitted from EGUs.

With regard to the comments relating to some state programs being more stringent than the EPA's proposed limits, the EPA would note that many of the programs identified by one commenter have an ''either/or'' format for their Hg standards. That is, an EGU can either meet an emission limit (*e.g.,* lb/TBtu) or achieve a percent reduction. The commenter did not note which form of the standard the EGUs were meeting so it is unclear whether the standards are in fact more stringent. In any case, CAA section 112(d) does not mandate that federal standards be more stringent than state requirements for HAP emissions. Furthermore, states are authorized to establish standards more stringent than this final NESHAP so promulgation of this rule will in no way affect a source's responsibility to comply with an otherwise applicable state Hg or other HAP standard.

9. Beyond-the-Floor

Comment: Several commenters stated that the proposed beyond-the-floor Hg limit for low rank coal EGUs is based on too little data and is technically and economically unattainable, noting that the EPA's proposed beyond-the-floor limit is based on only three samples from a single test held at only one EGU, which is not enough data to develop such a limit, especially as more data were available for this EGU in the database. Commenters noted that although this one EGU may have been able to achieve the proposed limit during this one test, the three samples are not adequate to demonstrate the long-term ability of this EGU to meet that limit consistently, let alone the long-term abilities of the top 12 percent of all low rank coal EGUs to meet that limit consistently. Given Texas lignite's particularly high rates of variability of Hg concentration, and the inability to minimize this variability, the commenters believe that the EPA is obliged to have more, not less, data to support the proposed beyond-the-floor Hg limit for low rank coal EGUs. One commenter added that the EPA's decision to require a beyond-the-floor limit for the low rank virgin coal subcategory does not comply with CAA section 112(d)(2). Some commenters also contended that the EPA failed to include the cost of a baghouse in its beyond-the-floor analysis. They note that, according to the EPA, in order to comply with the proposed EGU MACT rule, units will either fuel switch to a lower Hg fuel or retrofit air pollution controls.

Response: The EPA notes that all of the low rank virgin coal-fired EGUs for which data were submitted in response to the 2010 ICR were meeting the Hg floor limit (11 lb/TBtu). Four of the EGUs have ACI systems installed and three of the four EGUs tested were also meeting the beyond-the-floor Hg emission limit of 4.0 lb/TBtu. Those three units were achieving control levels of greater than 95 percent (fuel to stack). The other low rank virgin coal-fired EGUs that are not currently meeting the beyond-the-floor emission limit do not have installed Hg-specific controls. An analysis of the Hg content of the fuel used during the 2010 ICR testing suggests that control in the range of 80 to 90 percent (fuel to stack) would be needed to meet the beyond-the-floor limit of 4.0 lb/TBtu. One low rank virgin coal-fired EGU achieved 75 percent control with no Hg-specific control technology (*e.g.,* ACI).

The EPA believes that its beyond-the-floor analysis is appropriate, including the costs analyzed. The EPA's cost analysis is meant to serve as an average for all sources in the subcategory recognizing that some EGU's costs will be more and some less; EGUs whose costs are higher are not exempted from the regulation. Further, five EGUs in the subcategory are meeting the final beyond-the-floor limit based on available data (*see* the MACT Floor analyses in the docket), and, in any case, CAA section 112(d) does not require that a specified percentage of sources in a category or subcategory be able to meet the MACT standard that is established. This is even truer for beyond-the-floor standards which are set at levels beyond what the average of the best performing sources are achieving in practice and instead based on what is achievable. Commenters have failed to provide any data that supports the contention that some EGUs in the subcategory will not be able to achieve the standards with additional controls.

Comment: Commenters indicated that the EPA has not justified a beyond-the-floor limit for Hg for new IGCC units. The EPA's choice of the beyond-the-floor Hg limit for new IGCCs is not derived from IGCC test data from the 2010 ICR and commenters allege that the EPA has not provided adequate justification for its decision from a technology capability assessment. Commenters note that ACI for Hg treatment of coal-derived syngas is not in use in any operating IGCC plant today, nor can it be used in the same fashion as it is used at conventional coal-fired EGUs. Commenters assert that the EPA also lacks data with respect to new IGCC units, yet the EPA proposed beyond-the-floor MACT limits for new IGCC sources. The commenters assert that the EPA's limits for new IGCC sources are based on beliefs, predictions, projections and design target assumptions. The limits from the 2007 DOE Report referenced in the preamble are based on environmental target assumptions. These IGCC environmental targets were chosen to match Electric Power Research Institute (EPRI) design basis from their Coal Fleet for Tomorrow Initiative. Commenter states that EPRI notes that these were design targets and were not to be used for permitting values. Commenters assert that the EPA has simply not justified its process for going beyond-the-floor for new IGCC units and that, without sufficient justification, the EPA actions are unsupported.

Two commenters provided permit information, based on IGCC units currently under construction, for PM and Hg emissions. One commenter requested that the proposed new MACT floor limit for PM be modified to address the two scenarios for duct burners at IGCC plants, syngas-fired and natural-gas-fired. The commenter requested the 0.050 lb/MWh limit be increased to at least 0.068 lb/MWh based on gross energy output from the combined cycle generating unit when operated with duct burners fired with syngas. The 0.068 lb/MWh value is consistent with the calculated emission ceiling for its permit to construct for this operating scenario. According to the commenter, there is not sufficient experience with syngas turbines for manufacturers to guarantee performance in the 0.050 lb/MWh range. The 0.0681b/MWh performance basis proposed by the commenter was calculated based on the emission guarantees that the commenter was able to obtain for a turbine fired on the syngas. The commenter also requested that the 0.050 lb/MWh limit be increased to 0.083 lb/MWh based on gross energy output from the combined cycle unit when operated with duct burners fired by natural gas. The commenter indicated that, depending on market conditions, the syngas produced at an IGCC may have more value as a raw material for producing co-products than it would have as duct burner fuel. Where that is the case, the economic viability of an IGCC would be enhanced by firing the duct burners on natural gas and diverting that syngas to manufacture of a co-product. The commenter's air permits are currently based on the use of syngas as duct burner fuel; however, the commenter is currently examining an alternative operating scenario that may result in amendments to the air permits to authorize firing natural gas in the duct burners. Commenter states that preliminary calculations indicate that the PM limit would need to be set at 0.083 lb/MWh gross energy output when operated with duct burners fired with natural gas.

The commenter also noted that there is not sufficient test data to precisely predict the Hg emissions performance of even the best-controlled IGCC units, other than that IGCC Hg emissions are expected to be much less than those for EGUs that directly burn coal. In its permit application, the commenter proposed to establish a new standard for Hg removal in IGCC units by treating the syngas in catalytic reactors. The catalytic reactor system is expected to achieve greater than 95 percent Hg removal using either sulfur-impregnated activated carbon or alumina catalyst. In the absence of actual stack test data, the commenter has had to estimate expected emissions based on engineering estimates of how much Hg may arrive in the syngas routed to the catalytic reactors. Based on these engineering estimates and 95 percent Hg removal in the catalytic reactors, the commenter believes that the resulting Hg emission limit for a state-or-the-art IGCC unit would be 0.003 lb/GWh, which is much less than the Hg emissions for EGUs that directly burn coal.

The commenter notes that IGCC units are still in their infancy. Funding for them will be very difficult or unavailable if there is a regulatory limit below the level that can be supported by vendor guarantees. Given the important role that IGCC units may have in meeting global energy and climate stability goals, the commenter believes it would be a mistake to erect barriers to the implementation of this technology. The commenter stated that the EPA can reevaluate the appropriate levels for future IGCC units after demonstration units which incorporate effective controls have been built and tested.

Response: The EPA is not finalizing the proposed new source standards for IGCC units. As commenters noted, EPA proposed beyond-the-floor limits for IGCC units based on the performance of PC-fired EGUs and solicited data from IGCC units that would represent what a new IGCC could achieve. We received information that there are new IGCC units permitted and under construction. The EPA believes one IGCC unit under construction for which permit data were provided is representative of both current technologies and of IGCC units that will be built in the near-term future. Therefore, the EPA believes these permit levels should be the basis of the new source IGCC emission limits and the Agency is finalizing the PM and Hg limits on that basis, as that source will be required to comply with its permitted limits once constructed and it is a similar source. However, permit limits were only provided for PM and Hg; therefore, the EPA is finalizing the new source limits for acid gas HAP based on data from the best-performing of the existing IGCC units for the respective HAP.

B. Rationale for Subcategories

Many commenters stated that the EPA should have proposed more subcategories, while others believed that too many subcategories were proposed. Many different issues were raised by commenters, and some of the key issues that were considered in the final rule (some of which led to changes in the final rule) include: the technical deficiencies in the definition for the low-Btu coal subcategory; additional subcategorization of the coal-fired EGU population; the need for subcategorization of distillate vs. residual oil-fired EGUS; the need for a limited-use subcategory for EGUs that operate for only a small percentage of hours during a year; and the need for a non-continental liquid oil subcategory for island units that have limited fuel options and other unique circumstances. The comments and the EPA responses are provided below.

In general, the EPA has reviewed the data provided and continues to believe that the coal-fired EGU subcategories proposed are the only ones supported by the data, though we have revised the basis for EGUs designed to burn low rank virgin coal as discussed above. The EPA may not subcategorize by air pollution control technology type as requested by a few commenters. Further, the EPA has reviewed the other suggested coal-fired subcategories and finds no basis for further subcategorization (*e.g.,* based on boiler design, boiler size, or duty cycle).

1. Coal Subcategories

Comment: Commenters noted that although other subcategories had been evaluated, including subcategorization of other coal ranks, no other coal rank subcategorization was proposed. Commenters submit there should be subcategories for the coal ranks of bituminous, subbituminous, and lignite. The commenters noted that such treatment would be consistent with past practice (*e.g.,* CAMR where the differences in the type of emissions of Hg due to the different chemical properties of coal within differing fuel ranks was discussed). Commenters note that activated carbon has been shown to be very effective when used in combination with low chlorine coals (such as western subbituminous coals); however, activated carbons can suffer from poor performance when used with high sulfur coals. Commenters indicate that firing high sulfur coals (especially when an SCR is also used) can result in sulfur trioxide (SO_3) vapor in the flue gas stream. The SO_3 competes with Hg for binding sites on the surface of the activated carbon (or unburned carbon) and limits the effectiveness of the injected activated carbon. But another commenter noted that an SO_3 mitigation technology, such as dry sorbent injection (DSI, *e.g.,* trona or hydrated lime), applied upstream of the ACI can minimize this effect.

Commenters also stated that without further subcategorization the economic impacts on individual Midwestern states will be particularly acute as huge segments of the U.S. coal reserve will be disenfranchised by this rule. According to the commenters, the EPA did not even attempt to legitimately analyze this issue and, thus, in their opinion the Agency's proffered rationale for declining to further subcategorize based on the acid gas standard is belied by the record. The commenters believe that the EPA needs to better align this rule with its previous position in CAMR and further subcategorize based on coal type.

Other commenters are opposed to any further subcategorization based on coal rank. Because many sources blend several ranks of coal on a regular basis, commenters believe that establishing coal rank subcategories would create numerous opportunities for sources to game the regulations and substantially increase emissions. Commenters stated that there is no need for such an approach since modern pollution controls can accommodate a wide range of coals. These commenters believe that EGUs firing different ranks of coal are not fundamentally different in size, class, or type in a way that impacts emissions or that limits the availability of controls. The commenters believe that emissions of fuel-dependent HAP can be controlled by either changing the fuel prior to combustion or by removing the HAP from the flue gas after combustion. Commenters state that ACI systems, DSI controls, and PM controls are available for installation at units firing sub-bituminous coal and are equally available for units firing bituminous, anthracite, or lignite coal. These commenters also believe that as long as a control option is commercially available, the cost for a particular EGU is irrelevant to the EPA's development of emission standards based on MACT. Commenters stated that subcategories based on coal rank would make a meaningful consideration of fuel switching impossible, contrary to the judicial mandate to consider substitution of materials in setting the floor and the statutory mandate to consider substitution of materials in the beyond-the-floor analysis.

One commenter stated that although they previously supported the subcategorization of coal-fired units on the basis of coal rank, they no longer object to grouping units that burn bituminous and subbituminous coals in a single category because the prior basis for subcategorization no longer exists. The commenter indicated that at the time of CAMR, it was widely recognized that although coal-fired units combusting bituminous coal, with its higher concentration of chlorine and, therefore, ionic Hg, could effectively limit Hg emissions by utilizing existing control technologies such as scrubbers, units burning subbituminous coal could not do so with the same controls because of the coal's higher levels of elemental Hg. The commenter stated that activated carbon was only a fledgling and unproven technology at the time; today, however, activated carbon has been proven, and units burning bituminous and subbituminous coal can achieve the same levels of emissions for Hg and other HAP. Consequently, the commenter believes the prior basis for subcategorization no longer exists and the commenter, therefore, agrees that coal-fired EGUs burning bituminous and subbituminous coals ought to be grouped in a single category.

Response: The EPA disagrees with commenters that additional coal-fired subcategories are warranted and has not provided any in the final rule. Commenters are correct that additional subcategorization was proposed in January 2004. Whether or not such subcategorization was warranted at that time, the EPA believes that the current conditions are such that, even if appropriate at that time, such further subcategorization is not appropriate at this time.

When all of the factors noted by commenters have been reviewed, with the exception of Hg for certain units, as discussed above, the EPA does not believe that the HAP emissions to the atmosphere are sufficiently different from coal-fired EGUs to warrant further subcategorization. There are EGUs firing bituminous, subbituminous, and coal refuse among the top performing units for Hg and EGUs firing bituminous, subbituminous, lignite, and coal refuse are all among the top performers for the acid gas HAP and non-mercury metallic HAP indicating that the MACT floor limits established based on these units are achievable by units burning all ranks of coal.

As noted by commenters, ACI, not fully developed in 2004, is now able to effect Hg control levels on subbituminous coals such that similar emissions to the atmosphere may be achieved as those achieved by higher-chlorine bituminous coals when FGD systems are used or by coal refuse EGU with less controls. Thus, in looking at the total system, similar emissions to the atmosphere are achieved by all of these coal ranks. The EPA has addressed elsewhere in this document its rationale for not subcategorizing by coal chlorine content. The EPA does not believe that any fundamental discrimination between coal ranks will occur as a result of the final rule, though clearly some sources will be required to install greater controls to comply with the final standard. We maintain that such result is consistent with the intent of CAA section 112 standards, which are not intended to have an outcome whereby all sources can comply with final standards without any action.

The EPA agrees, in theory, that EGUs are designed around a basic set of coal characteristics. However, the 1999 ICR demonstrated that numerous EGUs have conducted trial burns and gained sufficient experience such that co-firing blends of various coal ranks is now common practice. In fact, the EPA believes that such blends may be modified daily, depending on the characteristics of the coal being burned and on the level of generation needed. The extent of blending, and the ability to switch the blends on short notice, does not lend itself (or, in fact, argue for) additional subcategorization.

The EPA disagrees with any assertion that the EPA ignored possible subcategorization approaches or that it has insufficient data upon which to base or evaluate various subcategories. The EPA fully examined the record, which demonstrates that coal-fired EGUs, with the exception of certain units for Hg, have similar HAP emissions profiles and that similar control approaches are available to such EGUs. Although commenters suggested additional subcategories were warranted, they failed to provide sufficient data to support their proposed alternative subcategories. As noted elsewhere, the EPA does not disagree with commenters that there are some differences in EGUs. However, the EPA does disagree with commenters that those differences result in differences in emissions to the atmosphere such that additional subcategorization is justified.

Failing to demonstrate that coal-fired EGUs are different based on emissions, the commenters turn to economic arguments, asserting that failing to subcategorize will impose an economic hardship on certain sources. Congress precluded consideration of costs in setting MACT floors, and it is not appropriate to premise subcategorization on costs either. See S. Rep No. 101–228 at 166–67 (5 Legislative History at 8506–07) (rejecting the implication that separate categories could be based on ''assertions of extraordinary economic effects''); *see also NRDC* v. *EPA* 489 F.3d 1364 (D.C. Cir. 2007) (holding that EPA properly declined to create a subcategory for a particular source and rejecting the argument that the source may have to incur more costs to comply with the rule without such subcategory).

The final limits are based on EGUs currently operating with available controls. As noted above, the record shows that the various types of EGUs are represented in the floors, with the exception of certain units for Hg, which indicates that the levels are achievable by such units. Thus, the data actually show that the MACT standards are achievable for a wide variety of EGUs.

In addition, the EPA believes it has fulfilled the CAA section 112(c)(l) directive that ''[t]o the extent practicable, the categories and subcategories listed under this subsection shall be consistent * * *'' with those of CAA section 111, notwithstanding commenters assertion to the contrary. The decision on whether to directly align CAA sections 112 and 111 subcategories is discretionary and EPA has reasonably exercised its discretion in declining to create additional subcategories for coal-fired EGUs based on the record, with the exception of certain sources for Hg.

Finally, the EPA disagrees with the commenters that suggest that EPA lacks the legal authority to consider material inputs when considering subcategories. We agree, however, that material inputs must be considered when establishing MACT standards for the subcategories that are established. We also believe a meaningful consideration of fuel switching can occur even if sources are subcategorized based on fuel inputs because EPA considers fuels switching in evaluating potential beyond-the-floor alternatives.

Comment: One commenter stated that the EPA should establish an existing source acid-gas subcategory for high sulfur or high chlorine coals because the same factors that the EPA relied on to support a low rank virgin coal subcategory for Hg are also present in the high sulfur or high chlorine coal context. The commenter stated that the data indicate that even well-controlled units burning high sulfur coals would not be in the top performers for acid gases even at removal rates of 95 or 96 percent. The commenter added that absent such a subcategory, about 12 percent of coal deliveries (2005 data), and the vast majority of coal shipped from the states of Indiana, Ohio, and Illinois (2008 data), would become unusable. The commenter expressed support for the alternative SO_2 standard for units unable to meet the HCl standard; however, the commenter also believed that it is appropriate to establish a coal chlorine or sulfur content-based subcategory for the alternative SO_2 standard. The commenter stated that coal testing data indicate a clear break in chlorine concentrations in the coals burned by EGUs, as well as in sulfur content. The commenter indicated that there are factors supporting a high sulfur or high chlorine coal subcategory that are similar to those that the EPA relied upon to support a Hg subcategory for low rank virgin coal. According to the commenter, the EPA's key rationale for a Hg subcategory for low rank virgin coal was that no low rank virgin coal-fired unit appeared in the ''top performing 12 percent of sources, indicating a difference in the emissions for this HAP from these types of units.'' The EPA did not establish other subcategories because ''the data did not show any difference in the level of HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for other HAP.'' The commenter indicated that the EPA does not need emissions data to know that even well-controlled units burning higher sulfur coals would be unable to meet the alternative SO_2 emissions rate, and would therefore also not appear in the top 12 percent of performing units.

Response: The EPA disagrees with commenters that subcategories should be established for high sulfur and high chlorine coals. It appears from the comments that it is not in fact the chlorine content that is at issue but the sulfur content of the coal. Commenters state that they are unable to meet the HCl limit, but they only provide information indicating it would be difficult to meet the alternative equivalent SO_2 limit. In fact, our data show that coals with chloride contents as high as 2,100 ppm (0.16 lb/MMBtu) were burned by EGUs making up the MACT floor pool of sources for the final HCl emission limit and that the best-performing unit was burning coal with a maximum chloride content of 1,200 ppm. The median chloride level for bituminous coals identified from data submitted through the 1999 ICR was 1,030 ppm so we believe that the coals represented in the MACT floor pool indicate that the final limits are achievable with high-chlorine coals. We have determined that HCl removal is very effective using a number of different types of FGD systems. Absent information demonstrating that sources are unable to meet the proposed HCl limit due to the chlorine content of the coal, we believe it is unnecessary and inappropriate to consider subcategorizing based on chlorine content in the coal.

In addition, as noted above, the SO_2 limit is an alternative equivalent standard that is available to sources that have an SO_2 control and CEMS and operate the controls at all times. The EPA did not provide the alternative equivalent standard for sources that could not meet the HCl limit as one commenter suggests; instead, we provided the standard as a convenience and cost saving measure to EGUs with installed FGD systems because we recognize that many EGUs have SO_2 CEMS. Sources are required to comply with the HCl limit as a surrogate for all the acid gas HAP or the SO_2 limit as an alternate equivalent standard. Commenters have not demonstrated that they are unable to meet the HCl standard and our data show that the standard is achievable even for high chlorine coals.

Comment: Several commenters supported the development of a separate subcategory for fluidized bed combustors (FBC) or circulating fluidized bed (CFB) EGUs. The commenters encouraged the Agency to consider subcategorization of FBC EGUs for Hg emissions noting that the industry has long contended that the design, construction, and operation of FBCs are different than conventional boilers and that FBCs employ fundamentally different processes than conventional PC-fired EGUs. The selection of an FBC unit over a conventional PC boiler is driven in large part by fuel characteristics. The commenters assert that, as a result, the emissions profile of FBC units generally differ from conventional PC boilers because FBC units more advantageously combust waste coals, as well as coal blends with other carbonaceous material. The commenters stated that the EPA did not discuss the design differences between FBC units and PC units in the preamble to this proposed rule unlike what the Agency did when it previously proposed Hg MACT limits in January 2004. Commenters state that, for these reasons, FBC units can be considered a distinct type of boiler.

The commenters noted that an examination of the 40 ''best performing'' units for Hg emissions in the proposed MACT floor spreadsheet showed that 14 of those units are FBC units. The commenters maintained that had FBC units performed as well as conventional PC boilers, 2 units would have been expected to be in the top 40. The commenters allege that the far higher percentage of FBCs in the top 40 leads to the conclusion that these units are different from conventional PCs with regard to Hg emissions and, as a result, should have been placed in their own subcategory. Further, commenters noted that the largest FBC has a nameplate capacity of about 300 MW while the largest conventional boilers have nameplate capacities of around 1,300 MW.

The commenters stated that FBCs combust relatively large coal particles in a bed of sorbent or inert material at a lower degree of combustion efficiency.

Fluidized bed units operate at less than half of the temperature of a conventional boiler and have much longer fuel residence times. Conventional boilers pulverize coal to a very fine particle size to maximize combustion efficiency and minimize unburned carbon. As a result, the commenters noted that FBCs typically have higher levels of unburned carbon present in the ash, which behaves much like activated carbon and helps promote more efficient Hg removal. Accordingly, commenters maintain that Hg emissions of FBC boilers and PC boilers are statistically different, with emissions from FBCs significantly lower than those from PC boilers. According to commenters, this statistically significant difference in the Hg emissions profiles for these two distinct boiler technologies argues in favor of the creation of a separate subcategory for FBCs, as there is no control technology that PCs could install that would result in emissions reductions similar to those achieved by FBCs. The active quantity of calcium oxide (lime-CaO) available in a FBC boiler is also orders-of-magnitude greater than compared to a PC boiler, whose alkalinity is derived solely from the coal's mineral content. Significantly higher CaO can alter the process chemistry in the boiler, including the oxidation levels of Hg.

One commenter stated that the EPA properly declined to subcategorize units based on design type where there is no indication that any physical distinctions among unit designs have a meaningful and substantial impact on HAP emissions. The commenter indicated that it would be inappropriate to subcategorize FBCs because there is no evidence to support a determination that FBC design is responsible for a unit falling in or out of the top 12 percent for a particular HAP.

Response: The EPA acknowledges that there are design and operation differences between conventional PC-fired EGUs and FBC/CFB EGUS; however, the commenters are incorrect in asserting that the HAP emissions levels and characteristics are sufficiently distinct from other coal-fired EGUs to support subcategorization. Further, commenters fail to note that FBC EGUs were not subcategorized in CAMR even though, as commenters note, such design and operation differences were cited there. The fact that FBC units operate at lower temperatures is of no consequence as they still operate at temperatures high enough to vaporize Hg.

Commenters assert that FBC units are disproportionately represented among the best performers, with the inference being that they were selected to test in the 2010 ICR because of their boiler design. However, FBC EGUs were not specifically selected as best performers for Hg, as EPA did not select any EGUs based on a determination that they were best performers for Hg (as noted elsewhere, we had no basis for selecting EGUs as being best performers for Hg), and to the extent CFB units were selected in the 2010 ICR, they were selected because we determined they were best performers for non-mercury metallic HAP, acid gas HAP, or organic HAP or because they were randomly selected among the non-best performers for those three HAP groupings. Thus, the CFBs were selected for testing under the 2010 ICR based not on their boiler design but, rather, based on the age and on their PM and FGD control systems (as noted in the Supporting Statement for the 2010 ICR). As many FBC EGUs, including CFB EGUs, are relatively new, they were included in the non-mercury metallic HAP group selected for testing (because their PM controls were among the 175 newest), the acid gas HAP group selected for testing (because FBC was considered to be an FGD system and the units were among the 175 newest), and organic HAP testing (because they were among the newest and, thus, determined to be among the most efficient).

The effect on Hg emissions is not what commenters suggest because, although, as noted by commenters, FBC units may be found among the better performers (among the top 10 EGUs) on the Hg MACT floor spreadsheet, they are also found in the range of 221 to 226 EGUs (of 393 data points). The fact that FBC units have ''vastly dissimilar ash properties'' that may contain higher levels of lime or unburned carbon in the fly ash than conventional PC EGUs does not indicate that the overall system behaves any differently with regard to emissions to the atmosphere (the key metric) than a conventional PC EGU with add-on controls. The asserted higher levels of unburned carbon result in a range of effectiveness of Hg control that is similar to that of ACI found on PC EGUs; such ACI control may be found on EGUs that are among the better performers as well as on EGUs as low as 369 on the list of data points. Thus, the EPA disagrees that FBC units are disproportionately represented in the Hg floor and that their inclusion is somehow inappropriate or leads to skewing of the analysis.

All types of coal-fired EGUs other than those we subcategorized are represented in the MACT floors for Hg and all types of EGUs are represented in the floors for the non-mercury HAP. Fluidized bed combustion EGUs are not an exception and such EGUs are found across the range of top performing EGUs for all of the HAP categories: Acid gas, non-mercury metallic, and Hg. In addition, any assertion that non-FBC EGUs are unable to meet the final standards because FBC EGUs are included in the same subcategory (or vice versa) is plainly refuted by the fact that EGUs of all types are currently meeting one or more of the final standards. Thus, the EPA finds no basis for subcategorizing FBC EGUs.

Further, as noted below, the EPA does not believe there is a basis for subcategorizing small EGUs, either FBC or PC. In addition, the data have been re-evaluated based on comments received and an FBC unit is not the basis for the new source Hg MACT floor.

Comment: Many commenters stated that the EPA should have considered additional subcategorization schemes, including one based on EGU size. Commenters noted that one of the factors that the Administrator can consider under CAA section 112(d)(1) in making subcategorization decisions is unit size. Commenters stated that an analysis of the 2010 ICR data showed a statistical difference between EGUs with a capacity of 100 MW or less and EGUs above 100 MW; other commenters suggested that the cut-off range should be 125 MW. Although large in number (about 27 percent) of all EGUs, these small EGUs only comprise about 5 percent of the coal-fired capacity in the U.S. Thus, commenters assert that if different MACT limits are set for this subcategory of EGUs, it will not have a significant impact on the health effects of HAP emissions. Commenters noted that although emission rates from such small EGUs are greater than those found in the large unit fleet, their contribution to the total EGU emissions is not significant. The costs associated with coming into compliance with the proposed rule by installing new controls would be proportionally much higher for these small EGUs than larger EGUs according to the commenters. The commenters allege that this would force the retirement of generation capacity and threaten electrical reliability without appreciable benefit to the environment.

One commenter stated that in general, the nature of many public power facilities differs from the general population of coal-fired power plants. Public power units tend to be smaller in size, and are often space-constrained by growth in the community surrounding the generating unit since its initial construction. These limitations restrict the ability of these EGUs to achieve the same performance levels of larger, unconstrained EGUs; and, for those EGUs that can comply with the proposed standards, the installation of controls sharply increases the cost of compliance. The commenter stated that the EPA did not adequately subcategorize to accommodate many small- and medium-sized public power utilities. In particular, the EPA did not avail itself of the opportunity to use a public power electric utility subcategory, rural subcategory, or fuel type subcategories. Other commenters endorsed the establishment of a less than 100 MW subcategory that would reduce the costs of the proposed rule significantly, but only affect 5 percent of the total electric utility sector, and help minimize retirement of uneconomical plants.

One commenter stated that the EPA properly recognized that subcategories based on unit size would be inappropriate because the proposed emission limits are in terms of lb/MMBtu or lb/TBtu and noting that an EGU's total nameplate capacity is wholly unrelated to its ability to achieve the proposed limits. Another commenter opposed any proposal to subcategorize units below 100 MW. The proposed rule does not apply to units less than or equal to 25 MW, and this commenter believed that this is a sufficient threshold for applicability.

One commenter stated that the EPA could establish subcategories for the purpose of temporarily exempting, for example, a subcategory of utilities that meet the definition of small entity for purposes of the proposed rule. The temporary exemption would sunset on a date certain (e.g., 3 years from the effective date of the rule) at which point the sources in the subcategory would become subject to the rule, and a compliance timetable would start to run. The commenter believed that this time-staged promulgation and compliance proposal would greatly increase the chance that the control measures could be added in an orderly and efficient manner with minimal disruption to power markets and grid reliability.

Response: The EPA agrees with commenters who stated that an EGU's size is totally unrelated to its ability to comply with the final concentration-based limits. The EPA examined the size of units within the respective MACT floor pools of sources and found units ranging in size from 25 to 1,320 MW in the HCl floor pool, from 25 to 869 MW in the non-mercury metallic floor pool, and from 47 to 544 MW in the Hg floor pool. Thus, we find no more difference between a 25 MW EGU and (e.g.) a 500 MW EGU than we do between a 500 MW EGU and a 1,300 MW EGU and reaffirm our position that the MW capacity of the EGU is not a determining factor in its emissions. Further, the EPA believes that units of all sizes are owned by both large and small entities.

The EPA examined the effect if EGUs less than 125 MW were subcategorized for Hg. The resultant MACT floor for these EGUs would be 1.0 lb/TBtu on a 30-boiler operating day rolling average, a level more stringent than that developed for the >8,300 Btu subcategory as a whole. We do not believe that this is what commenters envisioned when suggesting such a subcategory but we believe it confirms our analysis of the data that indicates, as noted, these units are controlled in the same manner as other, larger EGUs, such that additional subcategorization is not necessary or reasonable. Further, based on the number of EGUs less than 125 MW in the HCl and PM MACT floor pools, we believe that a similar analysis for HCl and PM would lead to similar or more stringent standards than without the additional subcategory. Thus, units of all sizes are capable of achieving the proposed limits and the EPA is not finalizing a subcategory based on unit size in the final rule.

The CAA authorizes EPA to subcategorize based on ''classes, types, and sizes of sources.'' The EPA does not believe that this provision permits subcategorizing sources based solely on their status as small entities for several reasons. As a threshold matter, commenters provided no information to suggest that EGUs at small entities are different from EGUs owned by other entities. Instead, the commenters' justification for such a subcategory was that the costs to comply with the standards make it more difficult for small entities; thus, the basis is essentially a cost basis and we do not think that is consistent with the statute. Moreover, the legislative history of CAA section 112(d) supports EPA's interpretation that subcategories cannot be based on the cost of compliance. *See* S. Rep No. 101–228 at 166–67 (5 Legislative History at 8506–07) (rejecting the implication that separate categories could be based on ''assertions of extraordinary economic effects'').

In addition, the EGUs owned by small entities use the same type of fuel as other units, have the same type of combustor designs, and can use the same types of controls, and so there is no difference in the HAP emissions from such units. So, even if we believed a subcategory based on small entities was consistent with the statute, we would decline to include such a subcategory.

Therefore, given the language of CAA section 112(d), the legislative history, and the available information, EPA is not creating a separate subcategory for EGUs owned by small entities.

In addition, the D.C. Circuit has clearly stated that the EPA does not have the statutory authority under CAA section 112 to extend compliance dates past the 3-year maximum compliance time authorized in CAA section 112(i)(3)(A) except consistent with CAA sections 112(i)(3)(B) and 112(i)(4). *See NRDC* v. *EPA,* 489 F.3d 1364, 1374 (D.C. Cir. 2007) (finding that ''Congress enumerated specific exceptions to the 3-year maximum, which indicates that Congress has spoken on the question and has not provided the EPA with authority under subsection 112(i)(3)(B) to extend the compliance date * * *'') (citing also CAA section 112(i)(4)). The EPA may not alter the compliance date based on size or ownership considerations and, thus, we are not providing a separate compliance date for different groups of EGUs in the final rule.

Comment: One commenter stated that the EPA should establish a subcategory consisting of EGUs that had received air construction permits but had not yet commenced construction as of the date of the EPA's proposed rule. The commenter believed that such a category would be justified because a substantial amount of time, money, and effort has been invested in these units. The commenter asserted that imposing new source standards on these EGUs for which the EPA's proposed rule had not been anticipated during their permit consideration would unreasonably and arbitrarily impose additional costs and burdens on these projects and would likely threaten the viability of many of them. The standards for this subcategory would be based on the anticipated performance of these units (as reflected by the permitted case-by-case emission levels), ensuring a reasonable and appropriate level of HAP control without unreasonably and arbitrarily interfering with the development of these units.

Response: Clean Air Act section 112(a)(4) defines a new source as ''a stationary source the construction or reconstruction of which is commenced after the Administrator first proposes regulations under this section establishing an emission standard applicable to such source.'' The EPA's regulations implementing the CAA section 112 General Provisions define ''commenced'' to mean ''with respect to construction or reconstruction of an affected source, that an owner or operator has undertaken a continuous program of construction or reconstruction 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 reconstruction.'' *See* 40 CFR 63.2.

The EPA is constrained by the definition of ''new source'' such that any source that ''commenced'' construction after the May 3, 2011, proposal date is considered a new source under the statute and the source must comply with the new source standards even if the source received a final and legally effective CAA section 112(g) permit before proposal. It is unclear from the comments whether the sources identified in the comments have commenced construction as defined in the regulations; however, the identified sources are existing sources, not new sources, under the final rule if construction was commenced prior to the proposal date.

Under the final rule, new sources must comply with the standards on the date of promulgation or at startup, whichever is earlier, and existing sources have 3 years to come into compliance with the final standards. Pursuant to the EPA's regulations at 40 CFR 63.44(b)(1), however, we may provide in a final CAA section 112(d) standard a specific compliance date for those sources that obtained a final and legally effective CAA section 112(g) case-by-case MACT standard and submitted the information required by 40 CFR 63.43 to the Agency before the close of the comment period. The EPA does not believe it has received such information during the comment period and we are not establishing a separate specific compliance period for sources that obtained final and legally effective CAA section 112(g) standards prior to promulgation of the final rule. In the absence of EPA action on this issue, state Title V permitting authorities are required to ''establish a compliance date in the [title V] permit that assures that the owner or operator shall comply with the promulgated standard [ ] as expeditiously as practicable, but not longer than 8 years after such standard is promulgated * * *'' 40 CFR 63.44(b)(2). Sources with final and legally effective section 112(g) standards should work with their permitting authorities to determine the appropriate compliance date consistent with the EPA regulations.

Comment: One commenter stated that in accordance with CAA section 112(d)(l), based on the government-to-government relationship of the Navajo Nation and the U.S. government, and consistent with the right of sovereignty and self-determination of the Navajo Nation, it may be appropriate to classify EGUs on tribal lands in a different subcategory from those on non-Indian lands. The commenter stated that in accordance with the distinctive status of Indian lands, based on principles of tribal sovereignty and self-determination, the government-to-government relationship, and the flexibility of federal agencies mandated under E.O. 13175, the EPA should classify sources on tribal lands as a unique subcategory of EGUs for which emission standards for NESHAP should be set pursuant to CAA section 112(d)(3).

Response: Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. In the preamble to the proposed rule, the EPA further explains that any basis for subcategorizing (*e.g.,* class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not agree that a subcategory based on location on Tribal lands is consistent with the statutory authority to subcategorize, and commenters do not explain why emissions would be different for EGUs located on Tribal lands. Absent that showing, EPA believes it would not be appropriate to subcategorize units even if we believed such a subcategory is consistent with the statute. CAA section 112 imposes specific requirements with respect to the methodology that the EPA must use in establishing emission standards for HAP, including Hg emissions from EGUs. Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. The EPA believes, that any basis for subcategorizing (*e.g.,* class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance.

However, the EPA is sensitive to the commenters' concerns and particularly recognizes the significance of Navajo Generating Station to the Central Arizona Project and the water delivery to tribes. As a result, EPA has been consulting with affected Indian tribes and working closely with other federal agencies, including the Department of the Interior, on these issues and intends to work with tribal and other authorities to ensure a smooth transition and address specific issues as they arise.

2. Oil Subcategories

Comment: Several commenters stated that distillate oil, and in particular ultra-low sulfur diesel (ULSD) oil, has fuel characteristics closer to that of pipeline gas than to residual oils. The metals, as well as the ash and nitrogen content, of distillate oils are very low, and the sulfur content of ULSD is approximately the same as that of pipeline natural gas. The commenters state that distillate oil is a more refined product than residual oil and, thus, burns cleaner. According to commenters, separating liquid oil-fired EGUs into two subcategories (distillate and residual oil) would be consistent with the discussion of subcategory differentiation in the rule's preamble which indicates that the division of a category into subcategories is justified if the two subcategories have very different emissions, which is true for distillate vs. residual oils. Distillate and residual oils are also differentiated by their operating requirements. Some commenters stated that as a consequence of the mechanical differences between boilers designed for residual oil vs. distillate oils, and between the fuel-handling requirements for the different fuels, it is not possible to interchange oil types without significant modifications to the oil storage tanks, transfer pumps, piping and valves, flow control systems, burners, and burner control systems. Commenters also noted that some of the EGUs in the EPA's liquid oil-fired database were mischaracterized with regard to the type of oil burned during the 2010 ICR testing.

Some commenters alleged that by combining distillate and residual oil into a single MACT category, the resultant MACT standards cannot be satisfied by a boiler firing residual oil without substantial add-on controls. The commenters asserted that creation of separate subcategories for liquid oil-fired units that distinguish between residual and distilled oil would render the standards more achievable for distinct subcategories of EGUs and reduce the number of potential plant closures while still advancing the goal of reducing overall emissions. These commenters contend that MACT floors should not be used to eliminate whole classes of existing EGUs through mathematical floor calculations based on data from uncontrolled units and combining boiler subcategories that are not capable of accommodating a different fuel.

One commenter stated that the EPA should not subcategorize liquid oil-fired EGUs based upon different grades of liquid oil. Although different grades of liquid oil may vary in their heat contents or viscosities, the commenter maintained that there is no indication in the rulemaking record that any physical distinction among units burning different grades of liquid oil affects the nature or characteristics of emissions in a way that impacts the availability of controls. According to the commenter, both distillate and residual oil-fired units can apply similar control technologies to reduce HAP emissions, and EGUs firing these fuels do not have physical distinctions that prevent controls from operating effectively. The commenter believes that fuel switching is an appropriate control technology and is available for liquid oil-fired sources. Residual fuel oil contains higher levels of contaminants, including HAP, than distillate oil, and because a regulated entity can readily burn cleaner distillate oil in lieu of residual oil, it is inappropriate to subcategorize based on the distillation fraction of the liquid oil. Thus, according to the commenter, the grade of liquid-oil fuel does not provide a reasonable basis for subcategorizing various groups of liquid oil-fired EGUs. Another commenter alleges that the EPA did not list distillate oil-fired EGUs in the 2000 Finding.

Response: The EPA has reviewed the data and determined that it is not necessary to subcategorize distillate vs. residual oil. Commenters had noted that the EPA's MACT Floor Analysis spreadsheet at proposal had erroneously assigned the oil type used during testing for some boilers. The EPA reviewed the data and determined that the submitting companies had entered the data incorrectly, or had indicated that two types of oil were fired in different parts of the 2010 ICR responses. The EPA contacted all of the companies with oil-fired EGUs in the 2010 ICR to confirm the oil used during testing. Upon review of these data, it became apparent that units using residual oil with ESPs or distillate oil without control were the best-performing oil-fired EGUs for PM and the HAP metals. Further, although emissions of HAP from distillate oil-fired EGUs are generally lower than those from residual oil-fired EGUs, EGUs burning distillate oil appeared to have higher emissions of some HAP but lower emissions of others.

In addition, the EPA does not agree that distillate oil-fired EGUs were not listed in the 2000 Finding. We believe it is inappropriate to exclude distillate oil-fired EGUs from regulation under the final rule because the Agency did not make a distinction when listing the oil-fired units.

The EPA also disagrees with commenters that by providing the distillate vs. residual oil subcategories as requested, the resultant standards would be more achievable. Were the EPA to subcategorize distillate oil from residual oil, the users of distillate oil would have no means of compliance other than obtaining ''compliance'' oil from their distributor (which was not indicated as an option by any commenter) or converting to natural gas and being removed from the subcategory. With no further subcategorization, oil-fired EGUs have the option of installing an ESP or converting to distillate oil for compliance. Commenters did not contend that it was impossible to convert to distillate oil, only that it would require plant modifications. Installing controls would also require plant modifications so sources will be able to evaluate the options and determine the most cost-effective option to comply with the final rule. CAA section 112 is intended to be a technology-forcing statute, and, because both distillate oil- and residual oil-fired EGUs were among the best performing sources in the floor and both types are meeting the final standards, we cannot reasonably conclude that the HAP emissions characteristics of these similar types of units are distinct. Therefore, the EPA is not establishing separate subcategories for distillate and residual oil-fired units in the final rule.

3. Limited-Use Subcategory

Comment: Several commenters stated that EPA should establish a limited-use subcategory for liquid oil-fired EGUs that are required to burn oil during periods of natural gas curtailment. One commenter stated that under New York State Reliability Council Rules, their facility is required by the New York Independent System Operator (NYISO), for reliability purposes, to maintain the capability to burn oil and actually burn oil, from time to time, at varying load levels to help avoid or avert potential natural gas shortages in New York City. The requirements to burn oil under this program are mandatory and are not within the commenter's discretion. The reliability rules require that the commenter's EGUs maintain their co-firing capability to respond to unplanned, emergency scenarios by operating on oil during required minimum oil burn periods, typically 25 percent oil/75 percent natural gas. The commenter noted that operation using oil at other times or on 100 percent oil during reliability operation periods occurs very infrequently; with natural gas expected to become more available in future years, such an operating scenario will become less likely. However, while the reliability rules remain in place and commenter's boilers are required to operate under his regimen, the commenter believed that it is essential that it be able to do so.

Other commenters noted that requiring installation of emission controls on oil-fired units that operate at a 10 percent oil-fired capacity factor or less is nonsensical and will result in little environmental benefit. Commenters contend that low-capacity factor units emit significantly less HAP than even well-controlled oil-fired units with much higher capacity factors. In addition, commenters allege that stack-testing at such units would be equally impractical and, in addition, would likely require the unit to operate on oil (and emit HAP just for the test) when it would otherwise be off-line or operating on natural gas.

Response: As stated above, after considering comments received, we are establishing a limited-use subcategory for liquid oil-fired EGUs with an annual fired capacity factor of less than 8 percent averaged over each 24-month block period after the compliance date.

At proposal, we solicited comment on establishing a limited-use subcategory for liquid oil-fired EGUs:

> EPA is also considering a limited-use subcategory to account for liquid oil-fired units that only operate a limited amount of time per year on oil and are inoperative the remainder of the year. Such units could have specific emission limitations, reduced monitoring requirements (limited operation may preclude the ability to conduct stack testing), or be held to the same emission limitations (which could be met through fuel sampling) as other liquid oil-fired units. EPA solicits comment on all of these proposed subcategorization approaches.

As stated above, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal. Some sources required to test under the ICR did not submit the data until after proposal. Commenters indicated that their units are different because many of them are only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.,* they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate.

Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil-fired EGUs as indicated elsewhere in this preamble. We find that these units constitute a different class and type of units because they are generally only used to address reliability issues associated with, for example, natural gas curtailments, and because they in fact only run for very limited periods in a year on a seasonal basis.

Although some commenters indicated a prevalence of natural gas/oil co-fired EGUs, the EPA also understands that there are other liquid oil-fired EGUs that do not co-fire natural gas but that could be subject to mandatory operation during periods of natural gas curtailment in their operating area if sufficient non-natural gas capacity is not available. Based on a review of units that report oil use to EPA, in 2010 there were 228 liquid oil-fired EGUs with a capacity factor of less than 5 percent and an additional 10 units with a capacity factor of between 5 percent and 10 percent. Only 2 of these units have capacity factors between 5 percent and 8 percent. This subcategory applies only to oil-fired EGUs that operate on oil alone and act as peaking units, as they generally address reliability issues. We are establishing the capacity factor threshold of 8 percent averaged over each 24-month block period after the compliance date.[320] In addition, as discussed below, we are establishing work practice standard for this subcategory in lieu of numeric emission standards.

Commenters that requested a subcategory for these units noted the dichotomy of establishing a NESHAP to reduce emissions of HAP to the environment while at the same time requiring an EGU to run for the sole purpose of conducting emissions testing and thereby emitting those same HAP. Because the operation of these units is infrequent and unpredictable, performing testing to demonstrate that emission limits are being met requires the sources to be scheduled to be operated merely for the purpose of performing testing. We realize that similar situations occurred in the gathering of emissions data through the 2010 ICR. However, unlike the case of one-time testing on a limited number of these units, such testing would be mandatory on a yearly basis for all of the EGUs upon the effective date of the final rule. Because requiring testing under this rule would in many cases require operators of these EGUs to schedule operation of these EGUs at times they would not otherwise run, it would result in both extra cost related to the testing as well as extra emissions; therefore, the Agency believes that it is technically and economically impracticable to monitor emissions for these EGUs, and that they should be subject to work practice standards that would not require emissions monitoring.

The annual average capacity factor would be calculated on a 24-month block period, commencing with the compliance date of the final rule. For example, assuming a March 1, 2015, compliance date, the first 24-month block would commence on March 1, 2015, and end on February 28, 2017, with the next 24-month block averaging period commencing on March 1, 2017. We believe the 24-month averaging period is reasonable to account for the fact that units needed to address reliability issues (e.g., natural gas curtailment periods) will be called to service sporadically. A 24-month averaging period provides flexibility to ensure that these units can run if there are large periods when natural gas is unavailable. As explained above, the data shows that most of these units operate for less than 8 percent of the time, and in fact it is usually less than 5 percent. Therefore, when considering whether these units would be able to perform stack testing, in many cases this will be for units that in fact operate significantly less than 8 percent of the time. In these cases, the EPA does not want to require the units to operate more just for the purpose of running a stack test resulting in additional pollution and cost. With projections for rising oil prices relative to natural gas prices, we expect this trend to continue. Liquid oil-fired EGUs subject to this subcategory would be required to conduct the same initial and periodic tune-up as all other affected units, but would have no other emission limit or work practice requirements.

Although the EPA believes that the ability to burn oil up to 8 percent of the time should address concerns about units that may need to operate using oil during gas curtailments. The EPA recognizes that if there were a period where gas use was more severely limited, such units might need the flexibility to operate for more than 8 percent in one year and less in the next, which is why we are providing the 2-year period; however based on the data we do not think EGUs in this subcategory will exceed even the 5 percent capacity factor that the data indicate is the average level for these sources.

4. Non-Continental Units

Comment: Commenters from affected island EGUs requested that non-continental EGUs be subcategorized from continental EGUs based on their lack of access to natural gas. The commenters urged the EPA to include a ''non-continental liquid oil'' subcategory in the final rule. According to the commenters, establishing a subcategory for non-continental units is consistent with the approach the EPA has taken in past rulemakings, including the final Industrial Boiler NESHAP. Non-continental EGUs have little or no access to natural gas, minimal control over the quality of available fuel, and disproportionately high operational and maintenance costs. All oil-fired EGUs operating in Hawaii, Guam, and Puerto Rico combust residual fuel oil exclusively and all are limited by the crude slates of their fuel suppliers. Island utilities can contract with suppliers for certain fuel specifications, such as sulfur content, pour point, flash point, API gravity and viscosity, which the refiners are able to meet primarily by blending and some sulfur removal during the refining process. However, the commenters state that the suppliers do not and cannot economically control for metal content. The crude slate feeding the refinery determines the HAP metal content of the residual oil produced according to the commenters. Because island utilities are dependent on local sources of fuel, they are equally limited by these factors.

Two commenters believe that the separate non-continental subcategory should be expanded to include continental areas that are not interconnected with other utilities and have limited compliance options due to remote locations (*e.g.,* Alaska).

Response: The EPA agrees that the unique considerations faced by non-continental EGUs warrant a separate subcategory for these units and the data show that the difference in location causes a difference in emissions apparently due to the fuel that is available for such units; thus, the Agency has included such a subcategory in the final rule. At proposal, the EPA did not have all of the data from liquid oil-fired units in non-continental areas (*e.g.,* Guam, Puerto Rico) and solicited comment on whether a subcategory should be established, based on the data to be received, for non-continental oil-fired EGUs. The EPA has now received these late data and, based on those data, is finalizing a non-continental subcategory for liquid oil-fired EGUs in Guam, Hawaii, Puerto Rico, and the U.S. Virgin Islands. The EPA is not aware of

[320] Units that co-fire oil and natural gas where the oil combustion comprises 10 percent or less of the capacity factor are natural gas-fired EGUs that are not subject to this final rule.

any liquid oil-fired EGUs in any of the other U.S. territories that meet the CAA section 112(a)(8) definition but, if there are such units, they would also be part of the non-continental subcategory.

The EPA agrees that the unique considerations faced by non-continental refineries, including a limited ability to obtain alternative fuels that lead to different emissions characteristics, warrant a separate subcategory for these EGUs. The EPA believes that units in this subcategory will comply through the use of cleaner oils or, for PM, through the installation of an ESP. The EPA finds no merit in the comment that Alaska should be included in this non-continental subcategory because utilities in Alaska are not faced with the same access issues affecting island-based facilities.

C. Surrogacy

1. Filterable PM vs. Total PM

Comment: Numerous commenters strongly objected to the use of total PM as the surrogate standard for non-mercury HAP metals. They argued that filterable PM is a better surrogate, especially given EPA's intent to use a PM CEMS for continuous compliance demonstration. Other commenters argued that we should not use a surrogate and instead should require direct compliance with a non-mercury HAP metals standard.

Response: We have decided to use a filterable PM limit for the PM surrogate emission limit in the final rule.

Although the objective of the emission limits we are establishing is to reduce the risks associated with HAP emissions, the limits are based in part upon the demonstrated capabilities of control technologies which are installed on existing sources. Except for Hg, the best PM controls provide the best controls of metal emissions. Emissions measurements of either filterable particulate, total particulate, individual metals, or total metals provide comparable indications that the best level of control is achieved. We can find no significant difference in the emissions that would be achieved by using any one of these emissions measurements.

We re-assessed the relationships between individual metal emissions, filterable PM emissions, total PM emissions, and total $PM_{2.5}$ emissions based on the test results provided through part III of the 2010 ICR. We compared the measured emissions of metals and PM with the uncontrolled emissions estimates and found that control of PM was indicative of the control of metals emissions. In addition, we compared the correlations associated with non-mercury HAP metal emissions and the three forms of PM and found that no specific particulate form provided a consistently superior indicator of better metals control. Although control of filterable PM provided the best indicator of performance for control of some HAP metals, control of total particulate or total $PM_{2.5}$ was nearly as good as an indicator. For control of other HAP metals, total PM measurement provided the best indicator of control performance because it included the vapor-phase metal HAP, although, measurement of the control of filterable particulate was nearly as good an indicator. In addition, certain data analyzed by our Office of Research and Development indicate that a vapor-phase metal, such as Se, can be present as an acid gas and reduced significantly using acid gas technologies (wet and dry scrubbing). Given that the rule also provides for acid gas control monitoring, and the general equivalency of the different indicators, we have concluded that use of a filterable PM limit as the PM surrogate emission limit is appropriate.

2. Moisture Content of Oil

Comment: A number of commenters stated that studies suggest that chloride in fuel oil can result from contamination during transportation and processing of crude oils and then be emitted as HCl during combustion. For example, the commenters asserted that the chloride contamination of crude oils can occur as a result of the ballasting of tanker ships with seawater. However, the Oil Pollution Act of 1990 requires all new oil tankers to be double hulled and establishes a phase out schedule (by the middle of the decade) for existing single hulled tankers with un-segregated ballasts. Because of the role of seawater contamination in introducing contaminants into the oil, the commenters suggest that the EPA set a percent water content limit for fuel oil at a level of 1.0 percent, rather than setting HCl and HF emissions limits. This would encourage handling and transport practices to limit salt water contamination. One commenter recommended a standard of 1.0 percent water because several of the lowest HCl and HF emitting units currently require percent water (or water and sediment) specifications between 0.5 percent and 1.0 percent.

Response: The EPA is providing the alternative compliance assurance approaches in the final rule for liquid oil-fired EGUs of demonstrating compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

The EPA is not aware of any FGD systems installed on oil-fired EGUs. Thus, it is only the quality of the oil, and the level of HAP constituents contained therein, that can be relied upon for ensuring compliance.

In the proposal preamble, we stated:

> We believe that chlorine may not be a compound generally expected to be present in oil. The ICR data that we have received suggests that in at least some oil, it is in fact present. EPA requests comment on whether chlorine would be expected to be a contaminant in oil and if not, why it is appearing in the ICR data. To the extent it would not be expected, we are taking comment on the appropriateness of an HCl limit. *See* 76 FR 25045.

Commenters refer to certain studies that provide a plausible reason for the chloride/fluoride contamination of fuel oils. We found this reason persuasive and accordingly are providing alternative compliance approaches in the final rule to demonstrate compliance with the acid gas HAP standards. Specifically, sources can demonstrate compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

D. Area Sources

Comment: Numerous comments were received both in support of and in opposition to the establishment of generally available control technology (GACT) standards for area source EGUs.

Several commenters in opposition to area source standards stated that the EPA properly established emissions limitations based upon the performance of all EGUs, rather than distinguishing between major sources and area sources. The commenters believe that Congress did not intend the EPA to distinguish between ''major source'' EGUs and ''area source'' EGUs in determining whether and how to regulate EGUs under CAA section 112. These commenters indicated that differentiating major source and area source EGUs for purposes of setting emissions standards is inappropriate in light of the 2000 Finding regarding the threat posed by the absence of regulation of HAP emissions from EGUs. The 2000 Finding was based upon studies whose conclusions regarding the impacts from EGU emissions did not depend upon any relevant distinction between major source and area source EGUs. The commenters note that segregating ''major source'' and ''area source'' EGUs would have the perverse effect of eliminating some of the best performing sources from the MACT pool of sources that constitute the ''best performing'' 12 percent. Many of the best performing sources have employed control technology that brings their emissions below the major source threshold, despite the fact that they are larger units. As a result, the commenters believe that if the EPA created standards for ''major source'' EGUs based only upon those units, the MACT standards for ''major source'' EGUs would be less stringent for each of the pollutants than proposed in this Rule. At the same time, the less polluting sources, the ''area source'' EGUs, could face limits more stringent than those proposed in the Rule. Commenters also note that after reviewing the substantial record in this rulemaking, they believe that the EPA has correctly determined that major and area source EGUs greater than 25 MW have similar HAP emissions and use the same control technologies and techniques to reduce HAP emissions. Thus, the commenters asserted that the record demonstrates that there is no technical basis for distinguishing between major and area source EGUs for purposes of establishing HAP emission control standards under CAA section 112(d).

Many commenters in support of an area source designation for EGUs stated that the EPA has promulgated area source limits for many source categories of HAP emissions, including most recently industrial boilers and note that GACT controls have been used successfully in many other EPA MACT rules, including rules for iron & steel foundries, electric arc steelmaking, coatings operations, clay ceramics manufacturing, glass manufacturing, and secondary nonferrous metals manufacturing, in order to reduce costs and regulatory burdens. The commenters state that Congress has given the EPA the ability to subcategorize area sources because of their low HAP emissions and low potential impact on human health and that, contrary to the plain language of CAA section 112 and its legislative history, the EPA made no attempt in the proposed rule to distinguish between major sources and area sources for purposes of listing or setting standards. The commenters indicated that where Congress was concerned about the health impacts of specific pollutants from specific sources, it knew how to specify that MACT limits be promulgated (*e.g.,* CAA section 112(c)(6)). The commenters state that area source rules would lessen the regulatory burden of a CAA section 112 EGU rule on many small entities (arguing that many EGUs owned by small public power entities are area sources) and that as many as 12 percent of the EGU population could qualify as area sources. A number of commenters pointed out that the small entity representatives (SER) on the SBREFA panel suggested that the EPA establish separate emission standards for EGUs located at area sources of HAP and that the standards be based on GACT as allowed under CAA section 112(d)(5). Specifically, the SERs recommended that the EPA establish management practice standards for area source EGUs.

Response: The EPA is not establishing an area vs. major source distinction in the final rule.

The CAA section 112(a)(8) definition of EGU does not distinguish between major and area sources, and we maintain that EGUs are a single source category that contains both major and area sources. The EPA proposed to regulate five subcategories of EGUs without distinguishing between major and area sources for purposes of establishing the standards for the different subcategories. Our approach is wholly consistent with the statutory definition of EGU and reasonable.

Nevertheless, the Agency did examine whether to set separate standards for area source EGUs, because we do not believe that the statute prohibits the Agency from exercising its discretion to establish GACT standards for area sources pursuant to CAA section 112(d)(5) if we determine such standards are appropriate. The EPA is not required, however, to establish GACT standards for area sources, and we believe it may even be unreasonable to do so under the circumstances we identified in the proposed rule as supported by the record of this final rule.

At proposal, we determined that it was not appropriate to establish separate standards for major and area source EGUs, and even if we had exercised our discretion to set separate standards, we would have likely declined to exercise our discretion to set GACT standards for area source EGUs given our appropriate and necessary finding and the fact that a potentially large number of area source EGUs are in fact large well controlled units.

Some commenters note that there could be as many as 12 percent of the total population that could be classified as area sources. We are not sure of the commenters' point in regard to this statement. As to commenters' statements that many of the area sources are municipal utilities, our information shows that many rather large EGUs (*e.g.,* hundreds of MW) are also area sources, and the commenters have not provided any justification for establishing GACT standards for large synthetic area sources.

Commenters did not provide an evaluation of the health and environmental impacts of the area sources and simply presume that the risks from such sources are lower, even though many of the same commenters noted that these smaller EGUs are often located in densely populated areas where populations are more likely to have adverse health effects from the HAP emissions. Furthermore, other commenters, including some industry commenters, noted that the vast majority of these potential area sources meet the criteria due to the installation of emission controls installed to meet other requirements. According to these commenters, these synthetic area sources would likely be able to meet the limits of this rulemaking and imposition of this rule would not appear to result in the installation of additional controls in a number of cases. We do not know if this assertion is correct but we determined approximately 69 coal-fired EGUs will be able to meet the existing source MACT standards with their current control configuration (out of 252 EGUs that reported data for Hg, PM, and HCl in the 2010 ICR).

Commenters also note that the Agency has exercised its discretion in other NESHAP rulemakings to establish area source limits. Although true, the fact that the EPA has established area source limits in some source categories is irrelevant to similar decisions for different source categories. Commenters have not shown that the circumstances applicable to those other source categories are similar to the circumstances identified for major and area source EGUs (*e.g.,* similar controls, similar emission characteristics, large number of synthetic minor area sources). Further, those other source categories are not statutorily defined in a manner that includes both area and major sources. EGUs are the only source category defined in CAA section 112 and, in establishing the definition of an ''electric utility steam generating unit'' under CAA section 112(a)(8), Congress included in the EGU source category both area and major sources. Thus, it is reasonable to regulate the EGU category in the manner Congress defined the category. Commenters have provided no legal support for the contention that the EPA must regulate area and major sources in the same category in separate rulemakings, and the EPA has in fact regulated both major and area sources in the same rulemaking even absent a statutory definition that includes both major and area sources. (*See* National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants; 75 FR 54970; September 9, 2010.)

The EPA considered the totality of the circumstances when determining whether to set separate area and major source standards for EGUs and also considered whether it would be reasonable to establish GACT standards for areas sources. We reasonably considered whether emissions characteristics of major and area sources are different when determining whether to establish GACT standards, notwithstanding commenters' assertion that such consideration is not correct. That we also consider emission characteristics in subcategorization decisions is of no consequence for area source decisions. Given that the statutory definition of EGUs contains both major and area sources, it was reasonable to evaluate whether there were sufficient differences between area and major sources when deciding whether to exercise our discretion to set separate area and major source standards.

In addition, we find commenter's point concerning CAA section 112(c)(6) odd because EGUs emit several of the CAA section 112(c)(6) HAP (*e.g.,* lead, Hg). Although EGUs were exempted from that provision, the fact that they emit some of the HAP called out for MACT control supports our decision to not establish GACT standards for any EGUs. CAA section 112(d)(5) leaves it to the Agency's discretion to determine whether GACT standards should be established for area sources, and the statute does not require GACT standards or even indicate that such standards are to be the default regulatory approach for area sources. *See* 76 FR 25021. Instead, the statute provides the Agency with discretion and we have exercised it reasonably in this case.

Commenters indicate that many EGUs owned by small entities are potential area sources. However, commenters fail to note that there are also EGUs owned by small entities that are not potential area sources, and, thus, would not accrue any ''lessened regulatory burden'' benefit from a decision by the EPA to establish area source standards.

Some commenters state that the EPA's mere assertion that there would be no difference between GACT and MACT to justify an area source finding does not provide sufficient documentation for the decision. But EPA did not say there would be no difference between MACT and GACT. Instead, it stated that it would be difficult to make a distinction given the similarities between the EGUs and major and area source facilities. Specifically, as noted by other commenters, and observable by a review of the MACT Floor Analysis spreadsheets, potential area sources range in size from units near the CAA section 112(a)(8) defined lower size limit to units of hundreds of megawatts. Further, these larger area source units are, for the most part, controlled with the full suite of emission control technologies available (*e.g.,* fabric filters, scrubbers).

In addition, the data that were available in the docket for the proposed rule show that there is little difference between major and area source EGUs individually, and that generally the driver for whether a utility facility is a major or area source depends on the number of EGUs located at a facility (almost exclusively one or two EGUs located at area sources), not on any inherent difference between the EGUs themselves. *See* ''Evaluation of Area Source EGUs'' TSD, Docket EPA–HQ–OAR–2009–0234. In fact there are a number of EGUs that are quite large that are area sources and others that are small that are major sources. *Id.* This is the case because the acid gas HAP emissions are what drive EGUs to have HAP emissions exceeding the major source threshold. With a few exceptions, the EGUs located at area sources have FGD or other acid gas controls that reduce the acid gas HAP to area source levels. *Id.* Thus, the majority of sources that currently qualify as area sources were, in fact, major sources prior to installing controls. The exceptions are those units that would likely be able to achieve the MACT level of control for acid gas with minimal use of DSI at a reasonable cost. *Id.*

In addition, the data show that a number of area sources for which we have data are high emitters of Hg and non-Hg metal HAP. *Id.* Pursuant to our appropriate and necessary finding, these HAP pose a significant threat to human health. Thus, even were we to distinguish between major and area sources, which we do not believe is appropriate given the similarities between such sources, we would still decline to set GACT standards, and as such we maintain that MACT standards are appropriate. Moreover, for acid gas HAP, as discussed above, the data indicate that the level of control would likely be the same even if we did establish GACT standards under CAA section 112(d)(5).

We fully evaluated the nature of EGUs, and we do not see a basis on which to distinguish these sources for purposes of setting standards. Thus, we maintain that we reasonably exercised the discretion afforded the Agency under the statute and declined to set separate standards for area source EGUs.

E. Health-Based Emission Limits

Comment: Many commenters noted that in the proposed rule the EPA considered whether it was appropriate to exercise its discretionary authority to establish health-based emission limits (HBEL) under CAA section 112(d)(4) for HCl and other acid gases and proposed not to adopt such limits, citing, among other things, information gaps regarding facility-specific emissions of acid gases, co-located sources of acid gases and their cumulative impacts, potential environmental impacts of acid gases, and the significant co-benefits estimated from the adoption of the conventional MACT standard. Comments were received both supporting this position and refuting it. Several commenters suggested legal, regulatory and scientific reasons for why HBEL for HCl might be appropriate for this MACT standard. With respect to legal concerns, some commenters indicated that CAA section 112(d)(4) establishes a mechanism for the EPA to exclude facilities from certain pollution control regulations and circumstances when these facilities can demonstrate that emissions do not pose a health risk. Commenters cited a Senate Report that influenced development of CAA section 112(d)(4), where Congress recognized that, ''For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment.'' (Footnote: S. Rep. No. 101–128 (1990) at 171.) Commenters also cited regulatory precedent for addressing HCl as a threshold pollutant, including the Hazardous Waste Combustors and the Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills NESHAP. Commenters requested that the EPA incorporate the flexibility afforded by CAA section 112(d)(4) and allow sources reasonable means for demonstrating that their respective emissions do not warrant further control. The commenters also cited the 2004 vacated Boiler MACT as precedent for HBEL for HCl. The commenters contended that the EPA failed to explain why the health-based emissions limitations it established in the 2004 Boiler MACT and the justification provided for those limitations could not be used in this case. The commenters also cited a 2006 court briefing where the EPA vigorously defended the HBEL included in the 2004 Boiler rule when it was challenged in the D.C. Circuit (Final Brief For Respondent U.S. Environmental Protection Agency, D.C. Cir. Case No. 04–1385 (Dec. 4, 2006) at 59–65, 69).

Other commenters stated that on August 6, 2010, the EPA adopted a NESHAP for Portland Cement plants that specifically rejected adoption of risk-based exemptions or HBEL for HCl and manganese (Mn). These commenters argue there are no differences sufficient to warrant a reversal of that decision in the EGU MACT standard. The commenters raised concerns that health risk information cited by the EPA for HCl, HF, and hydrogen cyanide (HCN) does not establish ''an ample margin of safety'' and, therefore, no health threshold should be established. The commenters believe risk-based exemptions at levels less stringent than the MACT floor are prone to lawsuits that could potentially further delay implementation of the EGU MACT.

Some commenters disagreed with using a hazard quotient (HQ) approach to establish a risk-based standard because the HQ would not account for potential toxicological interactions. The commenter noted that an HQ approach incorrectly assumes the different acid gases affect health through the same health endpoint, rather than assuming that the gases interact in an additive fashion. This commenter suggested that a hazard index approach, as described in the EPA's ''Guideline for the Health Risk Assessment of Chemical Mixtures,'' would be more appropriate.

Some commenters dispute that emissions from other EGUs or source categories should be considered when developing an HBEL and they argued that Congress expected the EPA to consider the effect of co-located facilities during the CAA section 112(f) residual risk program instead of under CAA section 112(d). Commenters added that there is no prior EPA precedent for considering co-located facilities from a different source category during the same CAA section 112 rulemaking.

Several commenters disputed the EPA's consideration of non-HAP collateral emissions reductions in setting MACT standards. They contended that the EPA's sole support for its ''collateral benefits'' theory is legislative history—the Senate Report that accompanied Senate Bill 1630 in 1989 and noted that the D.C. Circuit rejected this use of this theory since the Senate Report referred to an earlier version of the statute that was ultimately not enacted. Instead commenters suggested that other components of the CAA, such as the National Ambient Air Quality Standards (NAAQS), are more appropriate avenues for mitigating emissions of criteria pollutants.

Several other commenters suggested it is impossible to assess an established health threshold for HCl such that a CAA section 112(d)(4) standard could be set without evaluating the collateral benefits of a MACT standard. And, as described in the recently finalized cement kiln MACT rule, setting technology-based standards for HCl will result in significant reductions in the emissions of other pollutants, including SO_2, Hg, and PM. The commenter added that these reductions will provide enormous health and environmental benefits, which would not be experienced if CAA section 112(d)(4) standards had been finalized. These commenters contended that HCl and other dangerous acid gases produced by EGUs pose substantial risks to industrial workers, as well as surrounding communities, and must be limited by the strict conventional MACT standards.

Several commenters indicated that the current economic climate requires the EPA to balance economic and environmental interests and indicated that HBEL would help target investments into solving true health threats where limits are no more or less stringent than needed to protect public health. Many commenters provided estimates of compliance cost savings if an HBEL is included in this final rule. Some commenters stressed the importance of an HBEL for small entities affected by the regulations. Several other commenters suggested that the EPA should estimate the costs and environmental effects of the HBEL option compared to a conventional MACT standard in order to make an informed decision on the adoption of HBEL.

Response: After considering the comments received, the EPA has decided not to adopt an emissions standard based on its authority under CAA section 112(d)(4) for all the reasons set forth in the proposed rule.

The EPA notes that the Agency's authority under CAA section 112(d)(4) is discretionary. That provision states that the EPA ''may'' consider establishing health thresholds when setting emissions standards under CAA section 112(d). By the use of the term ''may,'' Congress clearly intended to allow the EPA to decide not to consider a health threshold even for pollutants which have an established threshold. As explained in the preamble to the proposed rule, it is appropriate for the EPA to consider relevant factors when deciding whether to exercise its discretion under CAA section 112(d)(4), and, notwithstanding commenters' assertions to the contrary, the considerations we include in our analysis are reasonable. The EPA has considered the public comments received and is not adopting an emissions standard under CAA section 112(d)(4) for the reasons set forth in the proposed rule and explained below. We note that this action is consistent with EPA's recent decisions not to develop standards under CAA section 112(d)(4) for the Industrial, Commercial and Institutional Boilers and Process Heaters and the Portland Cement source categories.

As explained in the preamble to the proposed rule, the EPA continues to believe that the potential cumulative public health and environmental effects of all acid gas HAP emissions, not just HCl emissions, from EGUs and other acid gas sources located near EGUs supports the Agency's decision not to exercise its discretion under CAA section 112(d)(4). Additional data for all acid gas emissions were not provided during the comment period, and the data already in hand regarding these emissions are not sufficient to support the development of emissions standards for EGUs under CAA section 112(d) that take into account the health threshold for acid gas HAP, particularly given that the Act requires the EPA's consideration of health thresholds under CAA section 112(d)(4) to protect public health with an ample margin of safety. We note here that EPA agrees with the commenter who pointed out that a better way to evaluate the potential health impact interactions of all acid gases would be to use the approach in EPA's ''Guideline for the Health Risk Assessment of Chemical Mixtures'' rather than a simple evaluation of individual HQ values for each acid gas, but we further note that use of such an approach requires a substantially greater knowledge of acid gas emissions than is currently available. We further note that, even if cost were a relevant factor in setting standards under CAA section 112(d)(4), since the data are not available that would allow us to develop an acid gas HBEL appropriate to protect public health with an ample margin of safety, we cannot determine whether such standards would have any cost savings associated with them or not. In addition, the concerns expressed by the EPA in the proposal regarding the potential environmental impacts and the cumulative impacts of acid gases on public health were not assuaged by the comments received because no significant data regarding these impacts were received.

The EPA also received comments recommending not only that the EPA establish emissions standards for acid gases pursuant to CAA section 112(d)(4), but that it do so by excluding specific facilities from complying with emissions limits if the facility demonstrates that its emissions do not pose a health risk. The EPA does not believe that a plain reading of the statute supports the establishment of such an approach. Although CAA section 112(d)(4) authorizes the EPA to consider the level of the health threshold for pollutants which have an established threshold, that threshold may be considered ''when establishing emissions standards under [CAA section 112(d)].'' Therefore, the EPA must still establish emissions standards under CAA section 112(d) even if it chooses to exercise its discretion to consider an established health threshold. A source-by-source standard is not mandated as some commenters seem to imply, and we are unsure how we could reasonably implement such an approach even if we determined such an approach was legally available. For these reasons alone, we concluded it was not appropriate to exercise our discretion to establish section 112(d)(4) standards for acid gas HAP emissions.

In addition, as explained in the preamble to the proposed rule, the EPA also considered the co-benefits of setting a conventional MACT standard for HCl. The EPA considered the comments received on this issue and continues to believe that the estimated co-benefits are significant and provide an additional basis for the Administrator to conclude that it is not appropriate to exercise her discretion under CAA section 112(d)(4). The EPA disagrees with the commenters who stated that it is not appropriate to consider non-HAP benefits in deciding whether to invoke CAA section 112(d)(4). Although MACT standards may directly regulate only HAP and not criteria pollutants, Congress did recognize, in the legislative history to CAA section 112(d)(4), that MACT standards would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program. *See* S. Rep. No. 101–228, 101st Cong. 1st sess. at 172. The EPA consequently does not accept the argument that it cannot consider reductions of criteria pollutants in determining whether to take or not take certain discretionary actions, such as whether to adopt an HBEL under CAA section 112(d)(4). There appears to be no valid reason that, in situations where the EPA has discretion in what type of standard to adopt, the EPA must ignore controls which further the health and environmental outcomes at which CAA section 112(d) is fundamentally aimed because such controls not only reduce HAP emissions but emissions of other air pollutants as well. Thus, the issue being addressed is not whether to regulate non-HAP under CAA section 112(d) or whether to consider other air quality benefits in setting CAA section 112(d)(2) standards—neither of which the EPA is doing—but rather whether EPA may exercise its discretion to regulate certain HAP based on the MACT approach and consider collateral health and environmental benefits when choosing whether to exercise that discretion. The EPA believes there is no legal principle that precludes it from doing so and commenters have not provided one.

F. Compliance Date and Reliability Issues

Comment: Multiple commenters asked that the compliance date be clearly stated as soon as possible, as well as that guidance be provided for utilities unable to comply with the stated timelines, to allow time for utilities to prepare for compliance. Commenters also asked that any decisions or policies on extensions be published in a rulemaking. In addition, commenters requested that the EPA establish, streamline, and simplify the process of applying for the 1-year extension under CAA section 112(i)(3).

Multiple commenters offered suggestions on methods for allowing more time for compliance, including EPA's authority under CAA section 112(n)(1)(A); state authority under CAA section 112(i)(3); Presidential authority under CAA section 112(i)(4); categorical extensions for publicly-owned or governmental facilities according to EO 13132, 13563, and UMRA of 1995; state-designed programs under the delegation provisions of CAA section 112; various Consent Decrees; Administrative Orders of Consent (AOCs); temporary waiver mechanisms; and adoption of MACT compliance schedules through minor permit modifications of a source's Title V federal operating permits. Absent such considerations for additional compliance time, many commenters suggested that the reliability of the nation's electric grid would be jeopardized as utility companies were forced to retire EGUs because they could not install the needed controls in the requisite time.

Compliance times requested by commenters ranged from 1 additional year (4 years total) to 6 additional years (9 years total). Multiple commenters requested that a utility be required to demonstrate good faith progress toward compliance to get any extension. Some commenters suggested that the EPA require utilities to submit a notice concerning which EGUs will be retrofitted or retired within 1 year of the effective date; that the compliance date align with the Power Year used by RTOs; and that the EPA clarify that retirement and any clean replacement power that complies with the NESHAP rule, including off-site combined heat and power and waste heat recovery, can be deemed ''controls'' under the CAA.

Commenters noted the specific situations related to small entities and their inability to compete with the larger, investor-owned utilities for financing and engineering and technical labor as well as the different process they need to follow for capital improvements. Multiple commenters asked that the EPA consider other simultaneous rulemakings (*e.g.,* Cooling Water Intake Structures; Coal Combustion Residuals; CSAPR, etc.) and extend the compliance period. Many commenters noted these other requirements and suggested that installation of the necessary controls could not be completed within the compliance period allowed under CAA section 112, even if a fourth year were to be granted by the permitting authority, citing examples of the times necessary for installation of various pieces of control equipment or replacement power.

Some commenters pointed to existing state programs (*e.g.,* Colorado, Oregon, Washington) and indicated that if states can demonstrate that overall emissions reductions would be equivalent or greater than those that would be achieved by the proposed rule, the EPA should delegate the CAA section 112 program to these states, even if the state emissions reductions would not necessarily occur on the same schedule (many state programs call for retirement of EGUs in years beyond the CAA section 112 compliance date). The commenters did not want the promulgation of the final rule to undermine the significant amount of work that may have been invested in creating state-specific programs to curb emissions within a reasonable timeframe. The commenters seek to make use of temporal flexibility, authorized under CAA section 112(i)(3), in obtaining delegation of the final rule to preserve the hard-negotiated comprehensive state-specific programs designed to yield greater emission reductions than the MATS alone.

Other commenters requested that no additional time be granted for compliance. These commenters reference a number of reports (*e.g.,* by the URS Corporation, by M.J. Bradley & Associates and the Analysis Group, and by the Bipartisan Policy Center) to indicate that not only is technology readily available, but that the technology can typically be installed in less than 2 years and that the electric industry is well-positioned to comply with the EPA's proposed air regulations without threatening electric system reliability. Commenters assert that, if electric system reliability were to be threatened in local areas as a result of the rule, the EPA has the statutory authority to grant, on a case-by-case basis, extensions of time to complete the installation of pollution control systems. One commenter stated that no additional controls would need to be installed in many cases and any coal unit should be able to comply with all of the standards. Another commenter noted that utilities that failed to plan ahead ''should not be permitted to use their own inaction to justify more time.'' Commenters noted that several major utility companies have anticipated the EPA's rules and are already taking action to ensure a reliable supply of electricity in their service territory and beyond. Other commenters agree that there is significant excess generation capacity in the country and reliability will not be threatened by the rule. According to one commenter, companies are already preparing for a 2015 compliance date, factoring in the capital expenditures required to comply and delays would undermine decisions that have already been made. Commenters cite, for example, recent electricity forward capacity market auctions in the PJM market for the period of 2014 and 2015 that indicate that the capacity markets cleared with electricity reserve margins of 20 percent; this is in excess of the default reliability targets used by the North American Electric Reliability Corporation (NERC) for the year 2015. One commenter quoted NERC, stating that NERC does not see impacts from proposed climate legislation or anticipated EPA regulation as a reliability concern. Another commenter noted that the Building and Construction Division of the AFL–CIO has stated that there is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology installation. In fact, according to the commenter, given the high levels of unemployment in the construction sector, these jobs are much needed.

A number of commenters expressed concern that the time frame for compliance with a regulation under CAA section 112(d) was too short for this industry and would result in compromising the reliability of electricity supply. Commenters asserted that reliability would be compromised in several ways: (1) EGUs might have to temporarily close if the owner or operator is unable to install controls on the unit within the 3-year time frame or 3 years plus one; (2) the timing of outages to install controls will cause short term closures that could threaten grid stability; (3) owner/operators may shut down EGUs rather than invest in retrofits to keep them running and that these closures may cause a loss of critical generation; and (4) the construction of replacement generation or implementation of other measures to address reliability concerns due to plant retirements could take longer than 3 years, and that units slated for closure may be necessary beyond the 3-year compliance period but will be unable to run because they have not installed the necessary controls.

Response: Clean Air Act section 112 specifies the dates by which affected sources must comply with this rule. New or reconstructed units must be in compliance immediately upon startup or the effective date of this rule, whichever is later. Existing sources may be provided up to 3 years after the effective date to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the ability to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls.

As is explained earlier in this preamble, the 3-year compliance window is based on the date that is 60 days after publication of this rule in the **Federal Register**. Because publication doesn't occur until several weeks after the rule is signed by the Administrator, the earliest required date for compliance would be sometime in March 2015. Because the last stage of control installations usually needs to occur when the unit is off-line and because scheduled outages are usually scheduled for the spring or fall months when peak electric demand is lower, this additional time is significant as it provides companies an additional outage period, the spring of 2015, to install controls.

The EPA has considered the concerns raised by commenters and has concluded that given the flexibilities further detailed in this section, the requirements of the final rule for existing sources can be met by most sources without adversely impacting electric reliability. In particular, EPA believes that the flexibility of permitting authorities to allow a fourth year for compliance should be available in a broad range of situations (as discussed below), and that this flexibility addresses many of the concerns that have been raised. Furthermore as indicated below, in the event that an isolated, localized concern were to emerge that could not be addressed solely through the 1-year extension under CAA section 112(i)(3), the CAA provides flexibilities to bring sources into compliance while maintaining reliability.

The EPA considered the impact that potential retirements in response to this rule will have on resource adequacy in order to gauge the rule's impact on reliability. In considering these impacts, the EPA considered both the analysis it has conducted as well as analyses conducted by a number of other groups. The EPA's analysis shows that the expected retirements of coal-fueled units as a result of this final rule (4.7 GW) are fewer than was estimated at proposal and much fewer than some have predicted.[321] The net capacity reductions projected by the EPA make up less than one-half of one percent of the total generating capacity in the U.S. and about one and one-half percent of U.S. coal capacity. Because concerns have been raised that the use of DSI may not be as prevalent as the Agency has predicted and because this could lead to more coal retirements, the Agency also performed a sensitivity analysis in which fewer DSI systems and more scrubber systems were installed. In that sensitivity, we see approximately 1 more GW of retirements. This small change would have only a very small potential impact on resource adequacy. When considering the impact that one specific action has on power plant retirements, it is important to understand that the economics that drive retirements are based on multiple factors including: expected demand for electricity, the cost of alternative generation, and the cost of continuing to generate using an existing unit. The EPA's analysis shows that the lower cost of alternative fuels, particularly natural gas, as well as reductions in demand, will have a greater impact on the

[321] The EPA's analysis also identifies a small amount of capacity loss (less than 0.7 GW) due to derating of certain units, as well as partially offsetting reductions in non-coal retirements in comparison with the base case. The net estimated reduction in capacity, in comparison with the base case, is estimated at less than 5 GW.

number of projected retirements than will the impact of this final rule.

The EPA's assessment looked at the capacity reserve margins in each of 32 subregions in the continental U.S. Demand forecasts used were based on EIA projected demand growth. The analysis shows that with the addition of very little new capacity, average reserve margins are significantly higher than required. The NERC assumes a default reserve margin of 15 percent while the average capacity margin seen after implementation of the policy is nearly 25 percent. Although such an analysis does not address the potential for more localized reliability concerns associated with transmission constraints or the provision of location-specific ancillary services (such as voltage support and black start service), the number of retirements projected suggests that the magnitude of any local reliability concerns should be manageable with existing tools and processes.

Several outside analyses have reached conclusions consistent with EPA's analysis. The DOE, in December 2011, published a report that looked at resource adequacy in the bulk power system when faced with a stress test which was a regulatory scenario far more stringent than EPA's regulations.[322] For this stress test, in addition to CSAPR and MATS requirements, each uncontrolled electric generator is required to install both a wet FGD system and a fabric filter to reduce air toxics emissions. If such installations are not economically justified, this scenario assumes that the plant must retire by 2015. In reality, as discussed previously, power plant owners will have multiple other technology options to comply with the regulations—options that typically cost less than installations of FGDs and fabric filters. The analysis finds that target reserve margins can be met in all regions, even under these stringent assumptions. Moreover, in every region but one (TRE), no additional new capacity is needed. In TRE, the analysis finds that less than 1 GW of new natural gas capacity would be needed by 2015 beyond the additions already projected to occur in the Reference Case. This analysis also finds that the total amount of new capacity that would be added by 2015 is less than the amount that is already under development.

In June 2011, the Bipartisan Policy Center issued a report analyzing potential collective impacts of EPA's pending power sector rules and concluding that ''scenarios in which electric system reliability is broadly affected are unlikely to occur.'' [323]

In August 2011, PJM Interconnection—the Regional Transmission Operator (RTO) responsible for planning and reliable operation of the bulk power system serving all or portions of 13 states in the Mid-Atlantic and Midwestern regions—issued a report analyzing the impacts of the CSAPR and the proposed MATS rule.[324] Although PJM's analysis assumes substantially more retirements than EPA projects, it nevertheless concludes that resource adequacy is not threatened in the PJM region. This is particularly significant, given that the PJM region is one of the largest and most heavily dependent on coal-fueled generation in the country. The PJM analysis notes, as EPA has acknowledged, that even where there is adequate generation capacity on a regional basis, localized reliability issues may emerge in connection with retirements that may need to be addressed.

The EPA has reviewed industry and NERC studies suggesting, contrary to the EPA's and these other groups' analyses, that EPA rules affecting the power sector (including this final rule, the CSAPR, EPA's proposed rule addressing power plant cooling water intake systems under section 316(b) of the Clean Water Act (CWA), and EPA's proposed rule addressing coal combustion residuals under the Resource Conservation and Recovery Act) will result in substantial power plant retirements. Some of these studies predict that such levels of retirements will have adverse effects on electric reliability in some regions of the country. Although the specifics of these analyses differ, in general they share a number of serious flaws in common that call their conclusions into question.

First, most of these studies make assumptions about the requirements of the EPA rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals or final rules. For example, a large proportion of the retirements projected by several of these studies is attributable to their inaccurate assumption that EPA's cooling water intake rule under CWA section 316(b) would require all or virtually all existing power plants to install cooling towers. In one study, the reliability effects reported are based on inaccurate assumptions that all existing EGUs with a capacity utilization factor of less than 35 percent would close, and that all in-scope electric generators would be required to install cooling towers within 5 years, whereas the not-selected options with closed cycle cooling in EPA's proposal envisioned that permit authorities could exercise discretion to allow facilities 10 to 15 years' time to comply. In most cases, these analyses were performed before the CWA section 316(b) rule or the MATS rule were even proposed; even analyses subsequent to the CWA section 316(b) proposal continue to inaccurately portray EPA's proposed approach.

Second, in reporting the number of retirements, many analyses fail to differentiate between plant retirements attributable to the EPA rules and retirements of older, smaller, and less efficient plants that are already scheduled for retirement because owners have made business decisions, based in significant part on market conditions, not to continue operating them.

Third, most of these analyses fail to account for the broad range of responses available to address electric reliability concerns associated with power plant retirements, including upgrades to the transmission system, construction of new generation, and implementation of demand-side measures. These measures are discussed at greater length below.

As a preliminary matter, none of these situations, either alone or in combination, will necessarily lead to an electric reliability problem. There is excess generating capacity in the U.S. today and in most cases an EGU that closes, either temporarily until it comes into compliance or permanently, will not cause a reliability problem. As explained above, our modeling of the impact of this final rule at the regional level projects retirements of less than one percent of nationwide generating capacity and confirms that there will continue to be adequate capacity in all 32 subregions of the country as sources comply with the rule.[325] This analysis shows that significantly less capacity will close in response to the final rule than might have under the proposal. Moreover, the regional modeling of retirements demonstrates that plants that close in response to this rule are spread out across the country rather than clustered in one area.

Outside analyses have identified many of the same flaws in studies

[322] U.S. Department of Energy, December 2011, ''Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations.''

[323] Bipartisan Policy Center, June 2011, ''Environmental Regulation and Electric System Reliability.''

[324] PJM Interconnection, August 26, 2011, '' Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants.''

[325] *See* Technical Support Document on Resource Adequacy in this Docket.

projecting large-scale retirements as a result of EPA's power sector rules. For example, on August 8, 2011, the Congressional Research Service (CRS)[326] issued a report concluded that studies that assert that EPA rules will cause reliability problems, often make assumptions about the requirements of the rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals. The CRS further noted that EPA's rules will primarily affect units that are more than 40-years old, that have not yet installed state-of-the-art pollution controls, and that are inefficient. Many of these plants are being replaced by combined cycle natural gas plants, driven more my lower gas prices than by EPA's regulations. The June 2011 Bipartisan Policy Center report referenced above likewise highlighted many of these same shortcomings in the studies in question.[327]

Although we do not expect to see any regional reliability problems, we acknowledge that there could be localized reliability issues in some areas—due to transmission constraints or location-specific ancillary services provided by retiring generation—if utilities and other entities with responsibility for maintaining electric reliability do not take actions to mitigate such issues in a timely fashion. There are many potential actions that could be taken to address this problem and multiple safeguards to assure a reliable electricity supply.

First, utilities can help to assure reliability through proactive steps in coordination with relevant planning and regulatory authorities. As we said in the proposal, early planning is key. The industry has adequate resources to install the necessary controls and develop the new capacity that may be required within the compliance time provided for in the final rule.[328] Although there are a significant number of controls that need to be installed across the industry, with proper planning, we believe that the compliance schedule established by the CAA can be met. Many companies have begun to do the detailed analysis and engineering and are ahead of others in their compliance strategy. There are already tools in place (such as integrated resource planning, and in some cases, forward auctions for future generating capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as this final rule.

Second, companies that intend to retire EGUs should formally notify their RTO (or comparable planning authority in the case of non-RTO regions), state regulatory agencies, and regional reliability entities as soon as possible of their compliance plans, particularly with regard to any planned unit retirements. As we said before, in most places a closing plant will not be a cause for concern for reliability. The same is true of any outages required for retrofitting of units with controls. To the extent there is concern, however, early notification will provide an opportunity for transmission planners, market participants, and state authorities to develop solutions to avoid a reliability problem. In RTOs with forward capacity markets, owner/operators that do not bid generating capacity that they plan to shut down will provide an advance signal to market participants to take action to assure adequate future capacity. In all regions, early and public notification will allow market participants, planning coordinators and state authorities, as appropriate and in a timely fashion, to bring new generation on line, put demand side resources in place, and/or complete any transmission upgrades needed to circumvent a potential issue. Most RTOs only require 45 to 120 days notification of closure. In combined comments to EPA, 5 RTOs suggested that such notification should be made no later than 12 months after this regulation is final in order to allow a smooth transitioning to action to avoid a reliability problem. The EPA strongly encourages sources to provide notice to the RTOs as early as possible and believes that responsible owner/operators should and will do the early planning for compliance and provide early notification of their compliance plans, especially where such plans include retiring one or more units.

On the supply side, there are a range of options including the development of more centralized power resources (either base-load or peaking) and/or the development of cogeneration or distributed generation. Even with the current large reserve margins, there are companies ready to implement supply-side projects quickly. For instance, in the PJM region, there are over 11,600 MW of capacity that have completed feasibility and impact studies; the units representing this capacity could be on-line by the third quarter of 2014.[329] The EPA notes, as well, that in the 3 years from 2001 to 2003, industry brought over 160 GW of generation on line.[330]

Demand side options include energy efficiency as well as demand response programs. These types of resources can also be developed very quickly. In 2006, PJM had less than 2,000 MWs of capacity in demand side resources. Within 4 years this capacity nearly quadrupled to almost 8,000 MW of capacity.[331] In addition to helping address reliability concerns, reducing demand through mechanisms such as energy efficiency and demand side management practices has many other benefits. It can reduce the cost of compliance and has collateral air quality benefits by reducing emissions in periods where there are peak air quality concerns.

With regard to transmission, recent experience also shows that, in many cases, transmission upgrades to address reliability issues from plant closures can be implemented in less than 3 years. For instance, when Exelon notified PJM of its intention to retire four units,[332] it was determined that transmission upgrades necessary to allow retirement of two units could be made within 6 months of notification, transmission upgrades for the third unit would require slightly over 1 year and transmission upgrades to allow the fourth unit to retire could be made in approximately 18 months.[333]

The CAA allows CAA Title V permitting authorities the discretion to grant extensions to the compliance time of up to one year if needed for installation of controls. *See* CAA section 112(i)(3)(B)). If an existing source is unable, despite best efforts, to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls. Id. Permitting authorities should be familiar with the operation of the 1-year

[326] James E. McCarthy and Claudia Copeland, Congressional Research Service, August 8, 2011, ''EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?''.

[327] Bipartisan Policy Center, June 2011, ''Environmental Regulation and Electric System Reliability.''

[328] As stated above, EPA has provided the maximum compliance time authorized under CAA section 112(i)(3)(A).

[329] Paul M Sotkiewicz, PJM Interconnection, Presentation at the Bipartisan Policy Commission Workshop Series on Environmental Regulation and Electric System Reliability, Workshop 3: Local, State, Regional and Federal Solutions, January 19, 2011, Washington, DC, *http://www.bipartisanpolicy.org/sites/default/files/Paul%20Sotkiewicz-%20Panel%202_0.pdf,* slide 6.

[330] Form EIA–860 Annual Electric Generator Report, *http://www.eia.gov/cneaf/electricity/page/eia860.html.*

[331] BPC slides cited above—slide 5.

[332] *http://www.exeloncorp.com/Newsroom/pages/pr_20091202_Generation.aspx?k=eddystone.*

[333] Cromby Units 1 and 2 and Eddystone Units 1 and 2—Deactivation Study, Updated September 7, 2010—*http://policyintegrity.org/documents/20100907-cromby-and-eddystone-retirement-study-posting-update.pdf.*

extension provision because EPA has established regulations to implement the provision and the provision applies to all NESHAP. *See* 40 CFR 63.6(i)(4)(A).

We believe that the permitting authorities have the discretion to use this extension authority to address a range of situations in which installation schedules may take more than 3 years including: staggering installations for reliability reasons or other site-specific challenges that may arise related to source-specific construction, permitting, or labor, procurement or resource challenges. Staggered installation allows companies to schedule outages at multiple units so that reliable power can be provided during these outage periods. It can also be helpful for particularly complex retrofits (*e.g.,* when controls for one unit need to be located in an open area needed to construct controls on another unit). The additional 1-year extension would provide an additional two shoulder periods (*i.e.,* seasons flanking annual high-demand periods) to schedule outages, thus enabling owners/operators to gain the full benefit of staggering outages in support of complex installations. The EPA believes that although most units will be able to fully comply within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. That fourth year should be broadly available to enable a facility owner to install controls within 4 years if the 3-year time frame is inadequate for completing the installation.

As we indicated at proposal, this source category is unique due to the large, complex and interconnected nature of electrical generation, transmission and distribution, and the critical role of the electric grid in the functioning of all aspects of the economy. The grid functions as an interconnected system that supplies electricity to end users on a continuous basis. Safe, reliable operation of the grid requires coordination among actions taken at individual units, including timing of outages for the installation of controls, derating, or deactivation. It was for this reason that we specifically addressed in the proposed rule reasonable interpretations of the phrase ''installation of controls'' in CAA section 112(i)(3)(B). We determined that it was important to provide Title V permit authorities with information that might be useful if they were asked to authorize a fourth year for specific EGUs.

The EPA took comment on whether the construction of on-site replacement power could be considered the ''installation of controls'' such that a fourth year would be available while the replacement unit is being completed for a unit that is retiring (*e.g.,* a case when a coal-fueled unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine). After reviewing the comments, EPA believes that it is reasonable for permit authorities to allow the fourth year extension to apply to the installation of replacement power at the site of the facility. The EPA believes that building replacement power constitutes the ''installation of controls'' at a facility to meet the regulatory requirements.

Commenters were generally supportive of the proposed approach described above, but a number of commenters suggested several additional situations that should be considered as the ''installation of controls'' such that it would be appropriate for permitting authorities to grant a 1-year extension beyond the 3-year compliance time-frame. In particular, commenters suggested that the 1-year extension should be available for a unit if a company's compliance choice was to retire that unit but doing so within the 3-year time-frame caused reliability problems for any of the following reasons: (1) Generation from the retiring unit is needed to maintain reliability while other units install emission controls; (2) new off-site generation was being built to replace the retiring unit, but the new generation was not scheduled to be operational within the 3-year time-frame and any gap between the time the existing unit retires and the new unit comes on line would cause reliability problems; and (3) transmission upgrades were needed in order to maintain electric reliability after the unit retired but could not be completed within 3 years.

While the ultimate discretion to provide a 1-year extension lies with the permitting authority, EPA believes that all three of these cases may provide reasonable justification for granting the 1-year extension if the permitting authority determines, for example, based on information from the RTO or other planning authority or other entities with relevant expertise, that continued operation of a particular unit slated for retirement for some or all of the additional year is necessary to avoid a serious risk to electric reliability.

In a case where pollution controls are being installed, or onsite replacement power is being constructed to allow for retirement of older, under-controlled generation, a determination that an extra year is necessary for compliance should be relatively straightforward. In order to install controls, companies will have to go through a number of steps fairly early in the process including obtaining necessary building and environmental permits and hiring contractors to perform the construction of the emission controls or replacement power. This should provide sufficient information for a permitting authority to determine that emission controls are being installed or that replacement power is being constructed. Because companies will need to develop this information early in the process and because a determination can easily be made as to whether the schedule will exceed 3 years, the EPA believes that Title V permitting authorities should be able to quickly make determinations as to when extensions are appropriate.

In the three cases related to retirement of a unit without construction of onsite replacement power, additional information is needed. The Title V permitting authority should request that the affected company or companies provide information, including, for example, from the RTO or other planning authority for the relevant region, the state electric regulatory agency, NERC or its regional entities, and/or FERC or the DOE, demonstrating that retirement of a particular unit within the 3-year compliance period would result in a serious risk to electric reliability.

The first two situations involving a retiring unit—where one or more related existing units are upgrading pollution controls or a new unit is being constructed off-site—are similar to the situation we discussed in the proposed rule wherein a retiring unit at a facility runs an additional year while a replacement unit on the same site is constructed. In each of these situations, the retiring unit would be allowed to run so a unit compliant with the rule (either a retrofitted existing unit or a new unit) can come on line. We believe that these situations may, in the appropriate circumstances, constitute ones in which a 1-year extension for the retiring unit is ''necessary for the installation of controls.'' In these two situations, however, we believe that it would be appropriate for the Title V permitting authority to consider reliability concerns as a necessary factor before granting the additional year because continuing operation of the retiring unit is only ''necessary'' to the extent it is required for reliability. In each of these situations, the permitting authority should determine that the retiring unit is necessary to maintain reliability until the new unit comes on line or the other existing unit is retrofitted. Title V permitting authorities may determine that multiple retiring units are available to maintain reliability, but unless all the units are necessary to address the issue, it would likely be unreasonable to provide the additional year for all the identified units.

The third hypothetical situation identified above is one in which transmission upgrades are necessary to address a reliability issue resulting from the retirement of a unit in order to comply with this rule, where the upgrade cannot be completed by the 3-year compliance date. In terms of the functionality of the electric grid, this situation has some similarity to those discussed above. Here, it is the completion of the transmission upgrades, rather than bringing another compliant (retrofitted or new) unit on line, that would allow the retiring unit to come into compliance (by retiring) without threatening reliability. The general objective and result is similar: Reductions of the existing unit's HAP emissions (through retirement) while maintaining electric reliability. If such situations develop and the reliability problem has been properly demonstrated, permitting authorities should consider whether an extension under CAA section 112(i)(3)(B) may be provided.

The EPA continues to believe, based on the analysis discussed at the beginning of this section, that most, if not all, units will be able to comply with the requirements of this rule within 3 years. The EPA also believes that making it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in the range of situations described above, addresses many of the other concerns that commenters have raised. The EPA believes that the number of cases in which a unit is reliability critical and in which it is not possible to either install controls on the unit or mitigate the reliability issue through construction of new generation, transmission upgrades, or demand-side measures, within 4 years, is likely to be very small or nonexistent. This view is consistent with statements from commenters explicitly mandated with ensuring grid reliability.

The EPA's authority to provide relief from the requirements of this final rule beyond the fourth year is limited by the statute. If reliability issues do develop, however, the CAA provides mechanisms for sources to come into compliance while maintaining electric reliability. One area where the EPA has some measure of flexibility is with respect to the exercise of its enforcement authorities. The Agency has used such authority in the past to bring sources into compliance with the requirements of the CAA while maintaining electric reliability, although these authorities are not as flexible as suggested by some commenters.

The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly well in advance of the date when a violation may occur. In light of the importance of ensuring electric reliability, however, the Office of Enforcement and Compliance Assurance will separately publish a document that articulates our intended approach with respect to sources that operate in noncompliance with this final rule to address a specific and documented reliability concerns.

That document provides a pathway for reliability critical units (as such units are described in the document) to achieve compliance within an additional year. The result is that qualifying reliability critical units may come into compliance within up to 5 years. This pathway is structured to maintain reliability, to ensure CAA compliance and to increase certainty for sources in planning by allowing a unit owner/operator to determine whether it qualifies for a compliance schedule well in advance of the MATS compliance deadline.

The EPA believes that there will be few, if any, situations in which it will be necessary to have recourse to the processes discussed in the document just described, and that there are likely to be fewer, if any, cases in which it is not possible to mitigate a reliability issue within the further year contemplated under that document. However, there is always the possibility that some unit owner/operator will be unable to address its reliability issues within 5 years and there is always the possibility that a unit owner/operator will be unable to timely comply with the MATS for some other reason. Consistent with its longstanding historical practice under the CAA, the EPA will address individual non-compliance circumstances on a case-by-case basis, at the appropriate time, to determine the appropriate response and resolution.

A number of commenters also raised concerns about inconsistencies between the compliance timelines under this final rule and existing state agreements with specific owners/operators to install pollution control equipment and/or retire EGUs. The EPA believes the flexibilities provided in this discussion allow for some discretion to address those cases, but that they may not be fully addressed. The EPA is supportive of such efforts and believes they can have important multi-pollutant health and environmental benefits. To the extent that the flexibilities discussed here do not fully address a particular situation, we encourage states and sources to contact the EPA as early as possible to discuss their individual circumstances.

G. Cost and Technology Basis Issues

1. Dry Sorbent Injection

Comment: Several commenters stated that there is limited commercial operating experience in using DSI to control acid gas emissions from coal-fired boilers. They suggest that the technology is not adequately proven for use in this application.

Other commenters disagree with statements made that DSI is not proven. One commenter stated that DSI is a mature technology. The commenter indicated that DSI is well suited for units that burn fuels with lower or mid-level sulfur contents, and is among the viable options available for a number of sources to achieve the proposed HCl limits. Thus, the commenter believes that DSI represents a real technology control option for many units, and is among the suite of technology options that certain units will be able to employ to meet the proposed HCl limit.

Response: As explained in this response and elsewhere in this preamble, the EPA agrees that DSI technology is proven and ready for commercial use in controlling acid gases from coal combustion. One of the largest coal-burning electric utilities in the U.S, American Electric Power (AEP), pioneered the practical use of DSI with trona, a sodium-based sorbent, for SO_3 mitigation. American Electric Power has implemented trona injection for that purpose across its entire bituminous coal-fired fleet where both SCR and wet FGD systems are in place.[334] Examples of coal-fired EGUs already using trona DSI to control SO_2 emissions include NRG Energy's Dunkirk Generating Station Units 1–4 and CR Huntley Units 67 and 68 in New York.[335] The Dunkirk units range in size from 75 MW to 190 MW. Much larger units may also be economic when using DSI for SO_2 control, as suggested by Dominion Energy's studies of adding DSI on two

[334] *SO_3 Control: AEP Pioneers and Refines Trona Injection Process for SO_3 Mitigation,* Coal Power, March 2007, *http://www.coalpowermag.com/plant_design/SO3-Control-AEP-Pioneers-and-Refines-Trona-Injection-Process-for-SO3-Mitigation_29.html.*

[335] NRG Energy letter to RGGI, Inc, November 22, 2010, *http://www.rggi.org/docs/NRG_Nov_2010.pdf.*

625 MW units at the Kincaid plant in Illinois.[336] One of the largest suppliers of air emission control systems in the world, vouches that DSI is commercially proven for acid gas control:[337 338]

Comment: Numerous comments were received on EPA's IPM modeling of DSI in the MATS analysis. A few commenters stated that DSI will not work on bituminous coals. Some commenters stated that DSI is only suitable for use on low sulfur, low chlorine western coals. Others stated that DSI is only likely to be used on relatively small units, and that larger units would use scrubbers for acid gas control. Several commenters expressed the opinion that because there is little commercial operating experience in using DSI to control SO_2 emissions from coal-fired boilers, EPA's IPM modeling assumptions on the efficacy and cost of the DSI control option are unjustifiably optimistic. Some commenters believe that DSI will not be as economic or as widely applicable for either SO_2 or HCl control as projected by EPA's IPM modeling. Commenters observe that wet or dry scrubbers for FGD, longer-standing control technologies for SO_2 and HCl, are more complex systems with a much higher capital cost than DSI. These commenters argue that the sector will need to retrofit many more FGD scrubbers than projected by IPM for MATS compliance and will therefore experience a much higher overall cost of compliance than projected by IPM, as well as needing more time and resources for retrofit construction. A few commenters suggested that EPA should base its MATS modeling on this more conservative outlook. A few commenters were concerned that EPA's DSI modeling assumptions relied on performance data from only one DSI vendor.

Some commenters were concerned that fly ash currently sold for beneficial uses will become unsalable because it will be contaminated by injected sodium-based DSI sorbents. Two commenters argued that EPA's IPM analysis understates DSI cost by not including the costs of foregone fly ash sales revenue and contaminated fly ash disposal. A few commenters observed that landfilling of sodium-based DSI solid wastes will produce leachate containing sodium and other compounds that are challenging to handle, thus requiring special landfill designs and a high cost for landfill disposal of DSI waste.

Response: The EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

The EPA disagrees that its IPM modeling of DSI is overly optimistic and therefore underestimates the costs of MATS compliance. In its IPM modeling, EPA restricts the availability of the DSI option to only those units that use or switch to relatively low sulfur coal: Less than 2 lb SO_2/MMBtu (*see* IPM documentation in the docket). The EPA's IPM projections for MATS compliance, therefore, already include the costs of any additional FGD scrubbers that are economically justified and projected for use on units using higher sulfur coals. The EPA models DSI assuming fine-milled trona as the injected sorbent. As mentioned by several commenters, sodium bicarbonate (SBC), which is processed from trona, is also suitable for use with DSI. Sodium bicarbonate is more reactive with acid gases than trona. It would require less tonnage of sorbent and less tonnage of waste disposal than trona for the same SO_2 removal effect, albeit at somewhat higher sorbent cost. Non-sodium based sorbents such as hydrated lime (calcium based) could also be used. Therefore, EPA's modeling of DSI technology does not include the full spectrum of sorbent choices that real-world applications enjoy, meaning that there may be opportunities for lower-cost applications of DSI that are not captured in EPA's projections for MATS. The EPA models DSI with trona injection rates corresponding to 70 percent SO_2 removal for all coals, assuming that an equivalent amount of sorbent is needed to provide 90 percent HCl removal, regardless of the low sulfur and chlorine content of western coals.

Senior technical staff from the EPA have carefully evaluated the key assumptions regarding the cost and operation of emission control technologies. In general, these staff believe that trona should have strong HCl reaction selectivity and, consequently, EPA's assumed trona injection rates may be overstated. The extent to which this assumption may actually overstate DSI control costs can be observed through DSI pilot testing for Solvay Chemicals by the Energy & Environmental Research Center (EERC) at the University of North Dakota.[339] The EERC's testing of trona DSI on a central Appalachian bituminous coal (1.3 lb SO_2/MMBtu) substantiates the strong HCl reaction selectivity of sodium-based sorbents, including trona, and calcium-based hydrated lime. The EERC's pilot testing shows that fine-milled trona, when well mixed into 325 °F flue gas upstream of a FF, provides 90 percent HCl removal at a SO_2 removal rate of less than 20 percent (as compared to EPA's modeling assumption of aligning 90 percent HCl removal with sorbent injection designed to achieve 70 percent SO_2 removal). The data show that 95 percent or higher HCl removal is readily obtained at somewhat higher SO_2 removal rates. Similarly strong HCl selectivity results were obtained using trona and an ESP at 650 °F. Test data from United Conveyor[340] on full-scale units also show these high HCl selectivity trends. Overall, these test data from multiple major vendors suggest that even if a SO_2 removal rate of 30 percent were required in order to obtain 90 percent HCl removal in the imperfectly mixed flow of a full-scale unit, it still appears that EPA's assumed trona injection rates may be as much as twice as high as would actually be needed in practice for certain applications. It is apparent that if EPA were to re-analyze MATS compliance with DSI injection rates reduced by 50 percent, there would be a corresponding reduction in the sorbent and related waste disposal costs that constitute most of the cost of using DSI.

Given the EERC test data, it is also apparent that most units that have ESPs and are burning low sulfur western coal could meet the HCl limit using DSI without the addition of a FF. If EPA were to re-analyze MATS compliance while allowing DSI use without the need for a downstream FF, it is apparent that there would be a very significant reduction in the overall number of FF retrofits projected, and a corresponding reduction in annualized capital costs. For the MATS proposal, the EPA modeled DSI on the assumption that all chlorine in coal converts to HCl, and that DSI would be the only mechanism by which the unit could prevent HCl from being emitted. Based on public

[336] Dominion Energy, *BART Analysis for the Kincaid Power Plant,* January 2009, *http://www.epa.state.il.us/air/drafts/regional-haze/bart-kincaid.pdf.*

[337] Dry Sorbent Injection Systems for Acid Gas Control, Babcock & Wilcox, 2010, *http://www.babcock.com/library/pdf/ps-451.pdf.*

[338] Technologies for Acid Gas Control, Babcck & Wilcox, 2011, *http://www.babcock.com/library/pdf/ps-457.pdf.*

[339] Solvay Chemicals, Inc., HCl Removal in the Presence of SO_2 Using Dry Sodium Sorbent Injection, *http://www.solvair.us/SiteCollection Documents/presentations/20111214_hcl_presentation.pdf.*

[340] United Conveyor Corporation, *Dry Sorbent Injection for Simultaneous SO_2, HCl, and Hg Removal,* October 2011, *http://unitedconveyor.com/uploadedFiles/Systems/Systems_Sub/McIlvaine%20Multipollutant%20Removal%20Oct%202011.pdf.*

comments and a more thorough review of the ICR data, the EPA has introduced in final MATS modeling a recognition that the relatively high alkalinity of ash from subbituminous and lignite coals ''removes'' much of the HCl that would otherwise be emitted from combustion of these particular coals. The 2010 ICR data indicate that in some cases the ash itself removes sufficient HCl from these coals for MATS compliance; in effect, these acid-gas emissions are absorbed by coal ash and are captured by particulate control devices instead of being emitted in gaseous form. As a conservative measure, EPA's revised final MATS modeling assumes that 75 percent of HCl is removed by the ash for these coals. In the event that ash capture in practice is more effective than this 75 percent assumption, then EPA's analysis projects a conservatively higher level of DSI installations (and, thus, compliance cost) than would actually occur in practice. In any case, it appears that significantly less sorbent injection would actually be required in practice than assumed by EPA for these low sulfur, low chlorine coals, and that the IPM projected DSI operating costs are likewise higher for these coals than would be experienced in practice.

The EPA models DSI with sorbent injection occurring downstream of an existing electrostatic precipitator (ESP). The existing ESP is assumed to remain in service. The model adds a fabric filter downstream of the DSI injection point to capture the small amount of PM passing through the ESP plus the reacted and unreacted DSI sorbent. Most of the DSI projected by IPM, therefore, includes the costs of a retrofitted FF. This modeled configuration allows fly ash currently captured in ESPs to remain uncontaminated by DSI sorbent and, therefore, remain available for sale and beneficial use. The EPA conservatively models FF costs based on an assumed full-size system with an air-to-cloth ratio of 4.0. The FF costs could be somewhat less in practice if a smaller system (with an air-to-cloth ratio of 6.0) were used for the reduced DSI dust loading. The EPA observes that some of the owners of units with ESPs may chose to convert existing ESPs into FFs,[341] an option not modeled in IPM, but that would likely have a lower capital cost than a retrofitted FF. In the MATS proposal EPA modeled DSI with a waste disposal cost of $50/ton, based on a Sargent & Lundy DSI cost model prepared for EPA (*see* proposal IPM documentation in the docket). The EPA has continued to model DSI at this waste disposal cost for analysis of the final rule. However, recent discussions between senior technical staff from the DOE and the EPA have suggested that in some situations sodium sulfates, that would be formed by the injection of trona, could potentially leach out of the fly ash/sorbent mixture on contact with water. Although the technical staff recognized that these concerns are more relevant to bituminous coal-fired units where ashes are not cementitious, unless mixed with limestone or lime, they suggested that the impacts of potentially higher disposal costs be evaluated. Based on public comments, further investigations by Sargent & Lundy, and suggestions from the EPA and DOE technical staff, EPA's analysis of the final rule has included an IPM sensitivity case using a DSI waste disposal cost of $100/ton. The sensitivity case indicates that a 100 percent increase in assumed DSI waste disposal cost produces slightly less than a 1 percent increase in the projected cost of the rule.

Comment: A few commenters expressed the concern that there is an inadequate supply of trona to support DSI operations at the levels projected by the EPA for MATS compliance.

Response: The EPA projects that just over 50 GW of coal-fired capacity might retrofit with DSI for MATS compliance, thus reducing SO_2 emissions by about 1 million tons per year. Based on conservatively high trona injection rates, as discussed above, the EPA estimates that the amount of trona required to support DSI operations at this level is about 4 million tons per year. By comparison, the trona mining industry in the U.S. has a demonstrated production capacity of at least 18 million tons annually, and was running well below that capacity (16.5 million tons) in 2010.[342] [343] If the EPA's assumed trona injection rates are as much as 50 percent greater than actually needed for at least 90 percent HCl control, as discussed above, and given that some subbituminous coals will apparently need little or no sorbent injection for HCl control, there may already be an adequate surplus of trona production capacity to support DSI for MATS compliance. The EPA, therefore, concludes that trona supply for DSI is either already adequate, or will require at most a small increase in production capacity.

For all of these reasons, the EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

2. Economic Hardship

a. Job Losses and Economic Impacts

Comment: Several commenters indicated that they believe the proposed rule will weaken industry, cause job losses and hurt power consumers. One commenter reported that the proposed rule will affect 1,350 coal and oil-fired units at 525 power plants and that NERC reports that by 2018 nearly 50,000 MW of capacity will be retired by the proposed rule. Many of these commenters compared the cost estimated by EPA to a variety of other sources that estimate substantially higher costs of the rule. The commenters expressed concern that electricity price increases are likely to be up to 24 percent in some regions as a result of the proposed rule. In addition to the economic difficulty the proposed rule could place on consumers, the commenter believes that many in the energy sector will lose their jobs due to coal-fired capacity losses. The commenters believe the effects on coal-fired plants in the Southeast especially will mean the loss of high-paying, high-skilled jobs and drastic price increases in energy costs. Additionally, commenters expressed concern that increased electricity and natural gas prices would impact businesses in multiple sectors across the country.

Response: The EPA disagrees with the estimates presented by the commenters. The EPA has updated its analysis to reflect the final MATS. The Agency estimates the annual costs of the final rule in 2015 to be $9.6 billion in 2007 dollars. The estimate of early retirements of coal-fired units due to this rule is 4.7 GW, lower than the level estimated at proposal. Both of these estimates were prepared using the IPM, a model that has been extensively reviewed and has been utilized in several rulemakings affecting the power generation sector over the last 15 years. The Agency's analyses are credible and accurate to the extent possible, and all assumptions and data are made public. Limitations and caveats to these analyses can be found in the RIA for this rule.

The EPA estimates that there will be an increase of 3.1 percent in retail

[341] TW Lugar, *et al., The Ultimate ESP Rebuild: Casing Conversion To a Pulse Jet Fabric Filter, a Case Study,* Electric Power Conference, May 2009, *http://www.cecoenviro.com/uploads/ESP%20to%20Fabric%20Filter%20Baghouse%20Conversion%20-%20Buell%20Case%20History.pdf.*

[342] *http://www.wma-minelife.com/trona/tronmine/tronmine.htm.*

[343] *http://www.wma-minelife.com/trona/TronaPage2/trona_production.htm.*

electricity price on average in the contiguous U.S. in 2015 as an outcome of this rule, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a result of this rule. To put this in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[344] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[345] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[346]

The Agency found that the readily discernible impact on long-term employment nationally within the most directly affected sectors should be small and the EPA also estimated that about 46,000 job-years [347] of one-time construction labor could be supported or created by this rule. This includes jobs manufacturing steel, cement and other materials needed to build pollution control equipment, jobs creating and assembling pollution control equipment, and jobs installing the equipment at power plants. Potential job increases from increased output by lower-emitting facilities (such as increased generation from well-controlled coal-fired plants that replace generation from older coal-fired plants) are expected to partially or fully offset potential job losses resulting from reduced output from higher-emitting facilities. The EPA analysis projects a net change in the directly affected EGU sector of between 15,000 net jobs lost to 30,000 net jobs gained on an annual basis.[348] See Chapter 6 of the RIA for further details.

The EPA has also looked at the possibility that changes in the price of electricity may influence the levels and geographic distribution of downstream economic activities, and associated employment. Projecting how potentially higher electricity prices may affect various downstream economic activities in particular regions as a result of this rule is challenging for several reasons: (1) There are significant uncertainties regarding projections of consumer- and location-specific electricity price changes in response to future firm-specific compliance strategies; (2) the availability of competitively-priced alternative energy sources (including energy conservation) and less electricity-intensive substitute goods and services may significantly mitigate potentially adverse economic consequences resulting from projected increases in electricity prices in ways which are not captured effectively in currently available models; and (3) available modeling tools are not configured to capture the effects over time of economically significant effects of cleaner air (*e.g.,* reductions in medical expenditures and improvements in labor productivity resulting from fewer lost work days) achieved by rules evaluated using single target year criteria pollutant and/or HAP benefits projections. After considering these methodological limitations, the Agency concludes that there is not a satisfactory methodology for projecting the downstream economic (including employment) effects of any changes in electricity prices due to this rule.

We expect the downstream economic effects of this rule to be small because electricity is only a small factor in the production of most goods and services.[349] A 3 percent increase in end-user electricity prices translates to a much smaller effect on prices and potential output of goods and services from end-users of electricity. Over time, the incremental effect of this rule on electricity prices is projected to diminish significantly; for example the difference in expected prices is projected to narrow from 3.1 percent in 2015 to 2.0 percent in 2020 as shown in Chapter 3 of the RIA.

Despite the absence of a satisfactory methodology for quantifying the potential economy-wide effects (including employment) of any potential increases in electricity prices resulting from this rule, the EPA expects the incremental effects of this rule on electricity prices to be small given the projected electricity price increases relative to historical levels and volatility in end-user electricity prices. Based on these projections and contextual information, the Agency believes that the incremental effects on electricity prices and economic activity of this rule are likely to be small relative to other factors influencing electricity prices, overall employment, and other aspects of economic activity.

Comment: Several commenters considered the proposed rule to be a tax on the American public, since utilities implementing upgrades will pass the costs on to the consumer. Commenters questioned the preference of Americans to subsidize renewable energy sources and put money into the proposed rule instead of other environmental programs with greater benefits. Commenters explained that the tax-like price increase reduces income of energy consumers and depresses business development. The commenters used California as an example of a state that uses low rates of coal-based electricity and cites companies that have left the state as a result of substituting higher cost forms of electricity for coal. A commenter stated that coal-derived energy will rapidly become more expensive, especially in the ''rust belt'' and Southeast region, as can be seen by the rate increase already requested in Louisville. A commenter believes the ''indirect taxation'' limits the ability of the economy to absorb the cost of retrofitting and new capacity projects, lowers discretionary spending and leads to job losses and lost tax revenues, given the restrictive timeframe for compliance.

Response: The Agency does not agree that this rule creates or alters any taxes on affected sources required under this rule to reduce their emissions of toxic air pollutants, nor are taxes created or altered or imposed on consumers of electricity which is provided to the market by affected sources. Moreover, unlike a tax, this rule does not generate government revenue. The rule does, however, indirectly address the problem of the ''externality cost'' of higher health risks and other adverse effects on the populations exposed to toxic air pollution emissions from affected sources. This rule may have the effect of

[344] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[345] Ibid, EIA AEO 2010, Table 8–10.

[346] Ibid, EIA AEO 2010, Table 8–10 for price levels; and Chapter 3 of the RIA for electricity price differential.

[347] A ''job-year'' is a combined measure of jobs and job duration which is equivalent to one person being employed for one year. For example, 2 job-years could represent two years of employment for one worker, one year of employment for two workers, or 6 months of employment for four workers. Estimates of employment changes that involve non-permanent workers are usually reported in job years to give a sense of the total employment effects.

[348] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

[349] BEA. (2007b). Commodity-by-Industry Direct Requirements after Redefinitions, 2002. Available in: *2002 Summary Tables, 2002 Benchmark Input-Output Data.* Retrieved from *http://www.bea.gov/industry/io_benchmark.htm#2002data.*

reducing or eliminating a market distortion that provides an implicit subsidy to affected facilities. This implicit subsidy results from the fact that some facilities currently can avoid the costs of toxic air pollution controls by imposing higher health and other costs on those who are exposed to higher levels of toxic air pollution. The Agency also disagrees with the implication that the costs incurred by less-controlled sources to bring their toxic air emissions in line with their better-controlled competitors will lead to significant or debilitating changes in market and economic conditions. The Agency's estimate of the potential increase in retail electricity price is an average of 3.1 percent in 2015, with a range of increases by region from 1.3 percent to 6.3 percent. As shown in Chapter 3 of the RIA, the higher rates of potential electricity price increase tend to occur in those regions where electricity prices have been relatively low, due to some extent to reliance on coal-fired units which have been cheaper to operate due to underinvestment in toxic air pollution controls.[350] As shown in Chapter 3 of the RIA, all regions with year 2015 projected percentage increases in retail electricity prices above the contiguous U.S. average are also projected to have baseline retail electricity prices which are below the contiguous U.S. average price level in that year. In addition, natural gas prices will only increase by 0.3 to 0.6 percent on average over the time horizon of 2015 to 2030. As discussed above, for consumers of electricity in the commercial and industrial sectors, electricity tends to be a fairly small fraction of total costs of production, implying that the average projected electricity price increase of 3 percent will lead to only a small fractional change in the costs of providing goods and services to the economy. While some residential electricity consumers may similarly see a small price increase in retail electricity prices, it should be noted that these consumers tend to reside in the same area or region as the affected facility and so will also experience the improvement in air quality from the reductions due to the rule. The reduction in health risk and other improvements to quality of life associated with lower exposure to toxic and other air pollutants achieved by this rule will confer benefits on these consumers which include lower risks of premature mortality, lower morbidity, and improved productivity and competitiveness of U.S. workers due to reduction in work days lost to air pollution-related illness. The benefits of these improvements are projected to exceed costs of compliance by affected sources by at least six-fold. The potential price increases in electricity and natural gas should be considered in light of the substantial health, welfare, and economic benefits achieved by this rule.

Comment: Many commenters expressed support for the EPA's impact analysis and disputed claims by other commenters that the projected rule will harm economic growth. A number of commenters mentioned testimonials by power company CEOs stating that the proposed rule will not affect the economic health of the industry and a survey showing nearly 60 percent of the coal-fired units already comply with the EPA's proposed Hg standard, and several other meaningful quotes from utility executives. The commenters also pointed out that 17 states already require plants to address Hg pollution, with some imposing more stringent emission limits than the EPA proposes. The commenters believe that utilities use the threat of power plant closures and lost jobs to delay Hg reductions from coal-fired plants. Commenters also believe that the rules will drive innovation and job creation as new technologies to reduce pollution are created. Several commenters quoted the Economic Policy Institute finding that the proposed rule will increase job growth by 28,000 to 158,000 jobs by 2015 (including approximately 56,000 direct jobs and 35,000 indirect jobs), the University of Massachusetts study that showed an increase 1.4 million jobs in 5 years, and the Constellation Energy Group installation project that employed nearly 1,400 skilled workers. Commenters also cited the University of Massachusetts study statement that a net gain of over 4,200 long-term operation and maintenance jobs will result.

Several commenters observed that the positive impacts of the rule strongly favor its adoption. These commenters stated that, contrary to the unfounded assertions by critics of EPA and the rule, EPA has conducted a technically sound and conservative benefit-cost analysis showing that the proposed rule's estimated benefits are at least five times as high as its costs. One commenter stated, ''With sound, albeit unduly conservative, econometric modeling, EPA has also determined that the Toxics Rule will promote economic growth and create jobs in both the long and short term.'' Two commenters cited the EPA impact analyses by Dr. Charles Cicchetti which confirm this finding and state that the analysis underestimates the rule's net benefits and positive impacts on the nation's economy. By considering some benefits not monetized in the EPA analysis, Dr. Cicchetti concludes that the proposed rule will create $52.5 to $139.5 billion in net benefits annually, create 115,200 jobs, generate annual health savings of $4.513 billion, annual increases in GDP of $7.17 billion and $2.689 billion in additional annual tax revenues, and spur innovation and modernization of EGUs. The commenters state that the study findings show no need to delay implementation of the rule or needlessly duplicate economic analyses already completed.

Commenters reported that multiple researchers confirmed that the EPA's estimates of economic stimulus are conservative and that the proposed rule will stimulate job growth. A commenter quotes Dr. Josh Bivens of the Economic Policy Institute, who also found that EPA's conclusions were conservative. Dr. Bivens concluded, ''The EPA RIA on the proposed toxics rule makes a compelling case that the rule passes any reasonable cost-benefit analysis with flying colors—the monetized benefits of longer lives, better health, and greater productivity dwarf the projected costs of compliance * * * Whether regulation in general and the toxics rule in particular costs jobs is an empirical question this paper attempts to answer. In particular, this paper examines the possible channels through which the proposed toxics rule could affect employment in the United States and finds that claims that this regulation destroys jobs are flat wrong: ''The jobs-impact of the rule will be modest, but it will be positive.'' His report details the following major findings:

1. The proposed rule would have a modest positive net impact on overall employment, likely leading to the creation of 28,000 to 158,000 jobs between now and 2015.

2. The employment effect of the [MATS] on the utility industry itself could range from 17,000 jobs lost to 35,000 jobs gained.

3. The proposed rule would create between 81,000 and 101,000 jobs in the pollution abatement and control industry (which includes suppliers such as steelmakers).

4. Between 31,000 and 46,000 jobs would be lost due to higher energy prices leading to reductions in output.

5. Assuming a re-spending multiplier of 0.5, and since the net impact of the above impacts is positive, another 9,000 to 53,000 jobs would be created through re-spending.

[350] *http://www.epa.gov/airmarkets/images/CoalControls.pdf.*

Response: The EPA thanks the commenters for these observations. The Agency's estimates of employment impacts, found in the RIA for the rule, are smaller than those identified by the some commenters, though the EPA uses a different methodology that focuses on impacts specific to the electric power sector.

b. Impacts on Low-Income Consumers

Comment: Commenters expressed concern that the EPA's overview of the price increases does not consider the hardships that will be the reality of increased prices on low-income or fixed-income households or small businesses. The commenter reports increases of $90 million in capital costs, $11.4 million in annual operating costs and $6.4 million in annual debt service costs to achieve compliance, which will lead to a 13 percent increase in rates for the proposed rule, and a 41 percent increase for all proposed and new regulation compliance costs. The commenter argues against the EPA's view that energy efficiencies will offset rate increases, because low income customers will need to use less electricity due to economic necessity. The commenter also sees large price increases for customers if units are converted to natural gas, which is approximately 2.5 times more expensive than the coal that the commenter currently uses to generate electricity.

Response: The EPA's estimates of increase, relative to the baseline, in the retail electricity price range from 1.3 percent to 6.3 percent regionally in 2015, with an average increase nationwide of 3.1 percent in 2015. Low-income households will thus see some increase in electricity price, but this increase should be modest. In addition, the increase in the price of natural gas as a result of this rule is expected to be 0.3 to 0.6 percent over a time horizon of 2015 to 2030. This increase in price is low enough that electricity customers should not experience a major increase in price resulting from any modest changes to electricity generated by natural gas. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[351]

c. State or Regional Impacts

Comment: Multiple commenters expressed concern over the impact of the rule on electricity prices and reliability in specific states or regions. These commenters were concerned that these impacts would adversely affect specific industries such as construction and manufacturing. One commenter suggested the EPA consider regional differences that will impact system reliability and costs, such as the increased impacts on regions relying heavily on coal and oil and encourages cooperation between the EPA and state and federal energy and environmental regulators.

Response: The Agency has studied possible impacts on resource adequacy as a result of this rule, and has determined that these impacts should not be significant. Furthermore, industry, along with relevant federal agencies, has the tools needed to address any reliability concerns. The Agency has prepared an updated feasibility TSD in support of the final rule, which is in the docket for this rulemaking.[352] The Agency has considered impacts on a regional basis as part of its overall analyses done using the IPM; these results are documented in the RIA for the rule and in the feasibility TSD.

The EPA's analysis shows that retail electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS. In Chapter 3 of the RIA, the EPA presents retail electricity prices by region in 2015, for both the base case and MATS policy case. The six regions that are projected to have retail electricity prices above the national average price in 2015 in the absence of MATS are projected to have increases that are below the national average increase following the implementation of MATS. Those regions that have projected retail electricity price increases that are above the national average are all projected to have retail electricity prices below the national average in the absence of MATS.

Comment: A commenter quoted National Mining Association statistics showing coal is responsible for $65.738 billion in annual economic activity, produces 1,798,800 jobs and $36.345 billion in annual labor income. The commenter reports that regions such as Appalachia, the Midwest and Rocky Mountain West will be significantly affected by the proposed rule, including increased unemployment. Other commenters stated that communities near existing coal-fired generation units will be especially hard-hit if the plants are permanently retired. The communities will suffer from job loss and diminished tax revenue.

Response: The Agency's analysis, as found in the RIA, shows that impacts to these regions are mixed. For Appalachia, coal production is projected to fall by 6 percent in 2015, while the Western coal producing region will experience a decrease of 3 percent in production in 2015. The Interior region is projected to see a 9 percent increase in production. Retail electricity prices are expected to increase by 1.3 percent to 6.3 percent in various parts of the country in 2015. Also, the estimated number of early retirements according to the Agency that may result from this rule is 4.7 GW in 2015, or less than 2 percent of all U.S. coal-fired capacity in that year. Thus, there may be some negative impacts from this rule in some regions, but these same regions will also experience some of the benefits, such as reduced premature mortality from less exposure to $PM_{2.5}$ emissions as shown in Chapter 5 of the RIA. As discussed previously, the EPA's analysis shows that retail electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS.

The results of the EPA's employment analysis, found in Chapter 6 of the RIA, indicate that the final MATS has the potential to provide significant short-term employment opportunities, primarily driven by the high demand for new pollution control equipment. While the employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements, some of these workers who lose their jobs due to plant retirements could find replacement employment operating the new pollution controls at nearby units. Finally, job losses due to reduced coal demand are expected to be offset by job gains due to increased natural gas demand, resulting in a small positive net change in employment due to fuel demand changes.

While shifts in employment are difficult for those directly affected, and the Agency remains concerned about the challenges job shifts can bring to the

[351] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[352] *See* ''An Assessment of the Feasibility of Retrofits for the Mercury and Air Toxics Standards Rule'' in the docket.

individuals affected, Bureau of Labor Statistics data indicate that compliance with pollution control requirements is a relatively very small contributor to overall employment shifts in the U.S. economy. Specifically, the main cause of mass layoffs over the last four years according to 2007 to 2011 Bureau of Labor Statistics data is ''lack of business demand,'' accounting for over 40 percent of the layoffs reported by industry. In contrast, all types of regulatory actions (including health, safety, and environmental) by all levels of government (Federal, State, local) combined were cited as the primary factor in only 0.2 percent of mass layoffs over the same period.[353]

d. Retirements of Coal-Fired EGUs and Shutdowns

Comment: A commenter discussed the economic factors behind EGU retirements. These factors include the cost of alternative generation using natural gas, the cost of implementing demand response measures that can be bid into capacity markets, and the cost of continuing to generate power from an existing unit. The commenter states that regardless of the costs associated with the Toxics Rule and other EPA electric power industry regulations, some power plants were already economically unsustainable. The commenter quotes M.J. Bradley, who points out, ''[o]f the 122 coal units in PJM with capacity less than or equal to 200 MW, 35 failed to recover their avoidable costs and another 52 were close to not recovering those costs. Therefore, in PJM * * * in addition to approximately 10 GW of coal generation that has or will be retired during the 7 years from 2004 to 2011, another 11 GW faces a troubling economic outlook.'' The commenter provides confirmation of this by the most recent PJM capacity auction, where approximately 6.9 fewer GW of coal-fired capacity cleared the auction (1.85 fewer GW were offered) as compared with the prior year's auction, and an additional 4.836 GW of new demand response (energy efficiency) resources cleared the auction. Thus, the commenter states, some claims linking retirements to the MATS are overstated and misleading. The commenter gives the example of the American Electric Power attempt to link its planned plant closures to the MATS, but those plants already are slated to either close or to upgrade controls to comply with existing laws. The commenter goes on to quote three independent studies that support the finding that over 50 percent of the fleet is equipped with scrubbers and the number will increase to nearly ⅔ by 2015.

Response: The EPA agrees with the findings of the independent studies mentioned by the commenter.

e. Impacts on Mining

Comment: Multiple commenters mention the proposed rule's impact on mining. One commenter mentioned increasing energy costs for the U.S. mining industry, resulting in fewer projects and associated jobs, as well as increasing dependence on foreign mineral resources. Commenters see mining impacts being disproportionally large for lignite mines, which are dependent on their co-located lignite-fired power plants. The commenters state that if the plant closes, there is no market for the lignite and the mine will also close, displacing plant workers. These impacts are largest in Texas, the largest coal consuming state and fifth largest coal producing state, as well as a deregulated electricity market. One commenter pointed out that the Texas coal market provided a buffer against natural gas price volatility and in particular believes the proposed rule does not take into account the emission reductions already achieved by industry in general and their company in particular. A commenter stated that impacts will be magnified in Texas, since it is the largest coal consuming state and mines lignite. A commenter indicated they believe it is unclear the extent to which EPA includes the impacts on the mining industry that will result from this rule.

Response: The Agency presents impacts on the coal mining sector from this rule in the RIA. Given the modest increase in coal and other energy costs associated with the rule, the Agency does not expect widespread impacts on coal mining. The Agency's modeling accounts for all emission controls and programs installed and/or implemented up through December 2010, including those in Texas.

f. Flexible Regulations

Comment: Several commenters expressed concern over the potential impacts of the regulation and believe that the requirements should be more flexible in order to mitigate these impacts.

Response: The EPA believes the requirements of the final rule have been made as flexible as possible consistent with the CAA. The final rule allows some flexibility, including allowing averaging across units in the same subcategory at a facility, allowing for an option of an input or output standard for existing units, and allowing for alternative compliance options (*e.g.,* for coal, filterable PM or total non-mercury metallic HAP or individual HAP metals). In addition, the Agency is not prescribing specific technologies as part of this final rule, but instead requiring emissions limitations be met. This approach allows the industry to find the most cost-effective approach to meeting the requirements while ensuring considerable public health benefits.

g. Temporary vs. Permanent Jobs

Comment: A commenter expressed disagreement with the EPA prediction of new jobs created, because the commenter believes far more plants will shut down than the EPA predicts, resulting in higher job losses. The commenter also pointed out that while jobs running power plants are permanent, the jobs predicted to be created by the proposed rule are short term construction jobs, and will all occur in the same short timeframe for compliance. The commenter also stated that the EPA estimate does not include the opportunity cost of lost construction jobs due to new power plants that will not be constructed due to the proposed rules.

Response: The Agency believes that the employment impacts of the final rule will be small, as has been the case historically with regards to environmental regulation. The Agency does provide an estimate of the long-term employment impacts to the electric power sector in the RIA for the rule, and that estimate shows a range of impacts from 15,000 net jobs lost to 30,000 net jobs gained (all annual), but also recognizes important limitations to these estimates. The Agency's estimate of impacts to short-term jobs, including those in construction, accounts for both losses and gains that result from the rule. This is shown in Chapter 6 of the RIA.

Comment: Commenters believe that installation of new pollution controls would be a job-growth opportunity in their states because money spent on controls for power plants creates high-quality jobs in steel, cement and other materials, as well as in the assembling of the equipment as well as installing and operating it. A commenter shares the Alabama Fisheries Association estimate that the water-based recreation industry brings in over $1 billion per year to the state's economy though the state ranks third for imperiled fish with 61 bodies of water cited for Hg contamination. The commenter believes the HAP accumulating in the waterways

[353] U.S. Bureau of Labor Statistics, 2011. Extended Mass Layoffs in 2010. *http://www.bls.gov/mls/mlsreport1038.pdf.*

threatens the industry with permanent job-losses and lost revenue.

Response: The Agency agrees with the commenter that the reduction in HAP that will take place as a result of the rule over time will help to improve waterways in Alabama and thus help the water-based recreation in that state. More information on the benefits of Hg and other HAP reductions can be found in Chapter 4 of the RIA for the rule. The Agency also agrees with the commenter that the addition of control equipment for EGUs may stimulate employment in a variety of industries.

h. Natural Gas

Comment: A commenter states that natural gas use is only an option in places where infrastructure exists to supply sufficient natural gas to the EGU and other local needs and reports that year-round reliable gas delivery is rare due to requirements to meet the other needs. The commenter says that gas interruptions are prevalent in the winter, but can happen year-round, and the costs of establishing a natural gas line to a power plant can be tens of millions of dollars or more, and moving a plant to a gas source can take many years. The commenter describes the options for a Norwalk Harbor plant, and explains that the modifications are costly and difficult even before considering the modifications needed to alter the boiler and fuel supply system to allow natural gas combustion.

Response: The final rule does not prescribe either pollution control technologies to be used, nor does it dictate the types of fuels that should be burned. The requirements of the final rule are designed to allow industry to find the most cost-effective approach to addressing harmful emissions that are covered by this action. The Agency believes that cost-effective technologies exist today and have been deployed on many power plants, and utilities will be able to find intelligent solutions to address harmful emissions. The EPA has provided supporting information as part of the preamble and RIA for this rule, along with the feasibility TSD, which demonstrate the availability and performance of technologies to meet the requirements of the final rule.

Comment: A commenter discusses the factors that could lead to higher natural gas prices not currently reflected in the EPA impact projections, including industrial load and demand not rebounding to 2008 levels and the influence of liquefied natural gas exports. The commenter asks that the EPA address a variety of factors related to its natural gas assumptions.

Response: The Agency has fully documented its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (*http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf*). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters.

i. Compliance Timeline and General Timeline

Comment: A commenter states that the proposed rule will require costs be passed on to consumers, meaning state public utility commissions will be flooded with requests for rate increases from utilities trying to recover expenditures. The short deadline will also result in a large number of extension requests made to state permitting authorities, further burdening them.

Response: The compliance date for this rule for existing sources will be 3 years and 60 days after publication of the final rule in the **Federal Register**, or approximately March 2015. Thus, there will be some time before the impacts of this rule such as any increase in retail electricity prices become a concern. It also should be noted that increases in retail electricity prices will be 3.1 percent on average in 2015, with a range regionally from 1.3 percent to 6.3 percent.

Comment: A commenter reports that they will need to install add-on pollution controls to meet the proposed emission standards as well as implement other physical or operational changes. The commenter expresses concern about the number of pre-construction steps that would be required, as well as the new construction activities and the challenges of scheduling sequence relative to interconnections and other tie-in considerations involved in compliance.

Response: The Agency has addressed concerns with the feasibility and timing of control installations in its report on the subject (*see* feasibility TSD contained in the docket for this rule).

Comment: Multiple commenters do not believe that labor availability will constrain control installation in the required timeframe and cites an Institute of Clean Air Companies (ICAC) response that it will not for these reasons:

1. The power sector has demonstrated ability to install large number of systems in short time period;
2. The majority of coal plans have installed control systems already;
3. Fewer resource and labor-intensive control options being used for compliance; and
4. End users have utilized cost reducing and implementation efficiency strategies for efficient deployment of technologies.

Another commenter states that a wide range of technical and economically feasible practices and technologies are available currently to meet the emission limits and are in use around the country.

Response: These comments are generally consistent with the conclusions of the Agency's analyses on feasibility of control installations for this rule as found in the feasibility TSD in the docket for this rulemaking.

j. Burden Outweighs Environmental Gain

Comment: Several commenters state that the EPA has no data relating to benefits from reducing non-mercury HAP, so the costs of the proposed rule exceed the HAP benefits by 29,000 times. One commenter states that the impact analysis was largely focused on Hg with little support for other HAP reductions and failed to provide account of true costs and benefits.

Response: While we are not able to monetize the benefits from reductions of non-mercury HAP that will take place, these important effects are discussed qualitatively in Chapter 4 of the RIA. The quantified benefits of this rule include the reductions in non-HAP emissions such as SO_2 and $PM_{2.5}$ that will occur as a co-benefit of this rule as modeled by EPA. The total benefits are estimated to outweigh the total annual costs of the rule by a margin of either 3 to 1 or 9 to 1, depending on the benefits estimate and discount rate used. These reductions are credible and are considerable in size. The estimates of these benefits reflect the latest scientific understanding on the subject. More information on the estimates and the methodology for their preparation can be found in the RIA for the rule.

Comment: Several commenters consider the proposed rule to be the most expensive clean air rule ever. They point out the estimated $10.9 billion annual cost in 2015 and approximate 1,200 existing coal-fired EGUs affected, both of which were estimated by the EPA. Commenters believe the EPA's estimates are incorrect and the true cost will be far more, due to cumulative effects of all proposed power sector rules, and indirect costs from job losses, reduced productivity and competitiveness resulting from electricity costs. They ask the EPA to keep these high costs in mind when evaluating impacts of the proposed rule and consider the costs with respect to the benefits. One commenter requests that the EPA explain how its approach utilized ''the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible'' and includes analyses by EIA, EEI, NERC, NERA, Credit Suisse, ICF, and Burns & McDonnell.

Response: As noted earlier, the Agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: (1) The various EO requirements that the Agency must comply with require us to estimate impacts specific to this rule; (2) decisionmakers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; and (3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, EPA makes clear statements about the impacts, costs, and benefits that are estimated as a result of this particular regulation.

This does not, however, mean EPA has failed to incorporate these regulations into this analysis. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at *http://www.epa.gov/air/sect812/feb11/summaryreport.pdf*). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments are estimated to reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at *http://www.epa.gov/air/sect812/prospective2.html.*

The direct benefits of the 1990 Clean Air Act Amendments and associated programs are estimated to significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits are estimated to exceed costs, combined with extensive uncertainty analysis, suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. The analysis presented in the RIA for the current regulation uses a similar methodology.

The techniques employed by the Agency for generating benefits and costs, and consider the most recent and complete data available to the Agency. The EPA recognizes that the analyses have caveats and limitations, and we discuss our analyses and their caveats and limitations in the RIA for the rule, as well as in the benefits section of the preamble. The Agency has also revised the cost analyses for the final rule to reflect data received in public comments on the proposed rule, and costs are lower than when the rule was proposed.

k. Impact on State Regulators

Comment: Several commenters expressed concern over the burden imposed on state regulatory agencies by the rule.

Response: The Agency has estimated the costs of implementation of the rule to states that own EGUs affected by the rule, and has included this analysis in the RIA. The Agency has updated this analysis for the final rule and it is included in the RIA. While the EPA has not prepared an analysis of the impacts of the rule on state programs, the Agency does not believe the rule will be unduly burdensome to the state regulatory agencies. The EPA works closely with state regulatory authorities to ensure that the rules are implemented properly, and the Agency will continue to do so in support of this final rule.

Comment: A commenter states that the reductions in SO_2 and $PM_{2.5}$ required by the proposed rule will assist state and local air pollution control agencies to meet health-based air quality standards, reduce haze and improve visibility. The commenter points out that substantial reduction in emissions made by the very large sources under the proposed rule will lead to fewer pollution controls needed at smaller sources to meet health-based ambient air requirements. This is a far more cost-effective approach than controls at smaller facilities and is the lowest cost path to improved public health and a cleaner environment.

Response: The EPA acknowledges that the HAP standards in this final rule will lead to considerable co-benefit reductions in PM and SO_2.

l. Miscellaneous

Comment: A few commenters discussed the impact of the rule on the federal budget deficit. One commenter points out that the proposed rule will affect the federal budget in two ways:

1. Direct compliance costs to electric generating units (EGUs) owned by federal agencies; and

2. Pass-through compliance costs paid in the form of higher prices for electricity purchased by federal agencies.

Response: The Agency estimates the direct compliance costs to EGUs that are federally owned as part of the overall cost analysis completed for the proposal and disclosed in the RIA for the rule. The Agency does not provide an estimate of the impact on federal agencies from higher electricity prices associated with the rule, however. This type of analysis is not required under EO 12866 and statutory requirements.

H. Testing and Monitoring

Comment: Commenters raised numerous issues with the testing and monitoring requirements for initial and continuous compliance. The following discussion highlights the comments and responses to a number of the critical issues and describe where the comments have resulted in a significant rule change or where we disagreed with commenters' suggestions of issues or need for changes in the rule. Additional comments and responses are addressed in the Response to Comments document included in the docket for the final rule.

Test Methods. A number of commenters suggested that we should allow for the use of Method 5B to determine compliance with the PM emission limit. In addition, a number of commenters objected to the frequency of stack testing when used as the method for demonstrating continuous compliance. Commenters also objected to the requirement for testing one pollutant when the source was complying with an optional surrogate (or vice versa); for example, commenters objected to testing for HCl if a unit was complying with the optional SO_2 limit, or testing for metals if the unit was complying with the optional PM limit.

Response: Although Method 5B is specified for wet scrubber-controlled utility boilers under 40 CFR part 60, subparts D, Da and Db, we are excluding Method 5B for demonstrating compliance with the filterable PM emissions standard in this final rule. The extended high temperature heating of the filters prior to weighing as specified in Method 5B would introduce differences between the compliance test data and the data that underlie the filterable particulate standard. Because the test data that underlie and filterable particulate standard are based primarily on Method 29 and Method 5 data collected at 320 °F or comparable filterable particulate methods, we are specifying those same methods for determining compliance with the standard.

For stack test frequency, we modified the final rule to require quarterly testing to demonstrate continuous compliance. In addition, we agree that testing should be required only for the emission limits that your source is complying with, and, thus, the final rule does not require testing of both the pollutant and the surrogate.

Comment: Fuel Analysis Methods. A number of commenters raised various concerns with the fuel analysis methods specified in the proposed rule.

Response: Based on the comments received and a further review of the technical challenges associated with the proposed fuel analysis requirements, we have not finalized the proposed fuel analysis requirements. As the rule no longer requires operating limits based on fuel content or fuel analysis, the comments on this issue are largely moot. For LEEs, we agree that the proposed LEE ongoing eligibility requirements were overly burdensome and restrictive. As a result, existing solid or liquid fired units that qualify for Hg LEE status will be required to conduct a 30-day test for Hg using Method 30B each year. Neither fuel analysis nor adherence to an operating limit will be required. Should an annual test show ineligibility for LEE status, the source will revert to the requirements for Hg monitoring using CEMS or sorbent traps or, for oil-fired units, quarterly emissions testing. Existing solid or liquid fired units that qualify for non-mercury LEE status will be required to conduct a stack test every 3 years, and neither fuel analysis nor adherence to an operating limit will be required. Should the stack test show ineligibility for LEE status, the source will revert to using CEMS or PM CPMS or conducting quarterly emissions testing.

Comment: Operating Parameter Limits: Some commenters objected to the use of enforceable operating parameter limits, requested that the rule be more consistent with the compliance assurance monitoring program, and raised specific objections to certain parameters required for certain control devices. Commenters also raised concerns about a PM CEMS operating limit establishing a de facto more stringent PM emission limit than the one being tested for under the total PM standard in the proposal.

Response: We believe that continuous monitoring in the form of CEMS, sorbent trap monitoring systems, and PM CPMS, or frequent stack emissions testing are appropriate to ensure ongoing compliance with this final rule. We also agree with commenters that some of the monitoring provisions in the proposal may have been duplicative and unnecessary. In order to provide flexibility in the final rule, we have retained a source's ability to define an operating limit and to monitor using a PM CPMS as an option to periodic filterable PM emissions testing.

The final rule establishes the PM CPMS as an operating limit monitor and not a direct filterable PM emission monitoring requirement that meets PS 11 requirements. Although we recognize the importance of continued control device performance to ensure emissions minimization, we also are aware that other rules that apply to these units including, but not limited to, the Operating Permits rule, the Compliance Assurance Monitoring rule, the ARP rules, and the NSPS already require continuous monitoring in most cases. Those rules will remain in effect so the need to impose additional operating limits monitoring or CEMS on those units is much reduced.

The final rule also provides for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of satisfying the requirements in Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60. The EPA provided this option in response to the comments in order to provide a straightforward direct measure of compliance that some sources may want to implement.

Comment: Hg CEMS. Commenters raised a number of technical concerns about Hg CEMS. Many commenters requested modifications so that the requirements would be more consistent with 40 CFR part 75 monitoring requirements. Some commenters questioned the ability of the technology to demonstrate compliance with emission limits at very low levels especially for new sources. Commenters also opposed high data availability requirements given that the technology is new and difficult to operate and maintain.

Response: We indicated in the proposed rule the intent to adopt CAMR-based requirements for Hg monitoring in place of the general 40 CFR part 63 performance specifications and QA requirements. With CAMR, these operating and reporting requirements for Hg CEMS went through notice and comment rulemaking for the same sources as covered by this final rule. Although CAMR was set aside on other grounds, these technical specifications and QA requirements reflect significant input from stakeholders and analysis by the EPA to establish an appropriate foundation for Hg monitoring at electric utilities under the CAA. For the final rule, we have made conforming changes to ensure that this intent is carried out effectively throughout the rule text and Appendix A, as well as including certain additional clarifications based on the input received in response to the proposed rule. We have also removed a cycle time test as unworkable for certain types of Hg CEMS.

The final rule provides the option for use of either Hg CEMS or sorbent trap monitoring systems. We believe the record clearly shows these to be proven technologies each providing certain advantages. For existing and some of the new unit standards, the level of the NIST-traceable Hg gas standards will be adequate and consistent with existing applications of Hg CEMS. For the lowest limits and other applications where an integrated sampling system offers advantages, affected facilities may opt to use sorbent trap monitoring systems to comply. There are data in the recent draft report entitled ''Determining the Variability Of CMMS At Low Hg Levels,''[354] that demonstrate reasonable

[354] *http://www.icci.org/reports/10Laudal6A-1.pdf.*

performance of at least one Hg CEMS at Hg levels below 1.0 microgram per cubic meter (μg/m^3) down to approximately 0.1 μg/m^3. Finally, there is no specific minimum data availability requirement for Hg CEMS (or any other CMS required under this final rule). This issue is discussed further below.

Comment: SO_2 CEMS: Although commenters were generally supportive of the ability to use SO_2 CEMS for units with FGD installed to demonstrate compliance with an alternate SO_2 emission limit instead of the HCl emission limit, there were some concerns with aspects of the proposal. Commenters requested that the SO_2 monitoring requirements rely on 40 CFR part 75 given that their sources were already meeting those requirements and that this rule not establish any new requirements, especially a fourth linearity level and the application of 7-day calibration error tests for units with low concentrations (where 40 CFR part 75 provides an exemption). Commenters were also concerned that the rule language only allows the option where the FGD is operated ''at all times'' which seems to imply that the option is not allowed if the source ever bypasses the FGD for start-up, shutdown, or malfunction reasons.

Response: After reviewing the comments and assessing the need for an additional calibration gas at the emissions limit, we have removed this requirement from the final rule while retaining the requirement for a linearity check even for SO_2 monitors with low span values (≤ 30 ppm). A source can already report linearity tests for these units within the context of the existing ECMPS reporting without triggering any critical errors. This test can be accommodated within the current framework without causing issues for 40 CFR part 75 reporting. The requirement for a 7-day calibration error test is removed. For the ''at all times'' language, we have clarified this in the final rule. The intent is that the FGD be operated during all routine boiler operations, and not operated intermittently, seasonally, or on some other non-fulltime basis.

Comment: HCl CEMS. In general, commenters argued that HCl CEMS do not have an approved performance specification and are not widely demonstrated as a proven technology. Those concerns were also mentioned for HF CEMS.

Response: We disagree with commenters' contention that continuous HCl monitoring is premature or not available for the measurement at the emission limits set in the final rule. HCl CEMS are being used on source categories such as municipal waste combustors and EGUs. We have reviewed HCl CEMS vendor technology claims and found sufficient capability to support this rule requirement. We are engaged with representative stakeholders to develop a generic performance specification for HCl CEMS scheduled for completion in time to be responsive to compliance with this rule.

The final rule provides several options for HCl and/or HF monitoring including:

(1) Using Fourier Transform Infrared (FTIR)-based HCl CEMS and/or HF CEMS complying with Appendix B to the rule which relies on PS 15,

(2) Seeking approval for an alternative HCl monitoring procedure through 40 CFR 63.7(f),

(3) Monitoring compliance continuously with the alternate SO_2 emission limit at coal-fired or other solid fuel affected facilities equipped with FGD technology for SO_2, and

(4) Quarterly reference method testing.

Including these options in the final rule provides flexibility to adopt CEMS monitoring options as the technology continues to mature and the new, non-technology-specific EPA performance specifications becomes available.

Comment: Bypass Stacks. Several commenters raised concerns about the technical feasibility of monitoring bypass stacks with a CEMS.

Response: We have modified the bypass stack monitoring requirements. Under 40 CFR part 75, we allow the use of a maximum potential concentration value for reporting when emissions are vented to a bypass stack. That approach works within the context of an emissions trading program, but is not appropriate when evaluating compliance with a specific emission limit. Thus, we have provided two other options. One is to monitor the bypass stack, consistent with the final rule. The other is to treat any hours of bypass stack emissions as periods of monitor downtime and hours of deviation from the monitoring requirements. Note that a source's units must continue to meet their 30-boiler operating day emissions limits during malfunction periods.

Comment: 40 CFR part 75 Issues. There were a number of general comments about the value of relying on 40 CFR part 75 requirements, including elements such as conditional data validation. The commenters generally agreed that the 40 CFR part 75 bias test and bias adjustment factor, and the 40 CFR part 75 substitute data provisions should not apply. Instead of substitute data, many commenters suggested that we needed to clarify the valid reasons for monitor downtime and establish an appropriate minimum data availability requirement.

Response: We have attempted to harmonize the CEMS requirements in this final rule with those under 40 CFR part 75 wherever appropriate. One of those examples is the inclusion of conditional data validation for Hg CEMS. We disagree that this final rule needs a minimum data availability requirement. We have not included any specific minimum data availability requirement for CEMS or other monitoring in this final rule nor do we provide a specific tool for data substitution. We believe that there are other provisions in the final rule to provide incentives to conduct monitoring in a manner consistent with good air pollution control practices and to provide data sufficient to demonstrate compliance with a relatively long-term (30-boiler operating day) emissions rate limit. We agree that data quality certainty associated with any calculated value decreases with the collection of less data such as would occur with extended periods of monitoring system downtime. Even so, we believe also that it is necessary and critical for compliance with the regulation that a source use all measured data collected during an averaging period to assess compliance regardless of any periods of missing data. Sources should not disqualify any data otherwise meeting required data quality requirements simply because there were data missing for other hours or days of the averaging period.

Instead of a minimum data availability threshold that would invalidate data collected for some averaging periods because one did not collect data for at least a specified percent of an averaging time, the final rule requires that a source report as deviations to the rule failure to collect data during required periods if these deviations are not covered by exceptions allowed in the final rule.

On the issue of applying a data substitution procedure to represent actual emissions or pollution control performance, we are not requiring data substitutions under this rule. We believe, however, that defensibility concerns make it incumbent on the source to collect and evaluate other information in accordance with 40 CFR section 63.6(f)(3) during periods of monitoring downtime to assure compliance with the applicable emissions limitations and standards.

We believe that enforcement authorities also can and should determine whether a source is meeting any monitoring system operating requirements. Should the source or the enforcement authority be concerned about the representativeness of data such as during periods of missing data, either one may consider collecting information through other means (*e.g.,* supplemental emissions testing) to fill data gaps not only because such gaps are deviations from the rule but such gaps can lead to uncertainty about compliance status.

We further believe that the final rule provides sufficient means to ensure CMS performance and ongoing compliance without specifying an arbitrary numerical minimum data availability or data substitution requirement. We believe that specifying failure to collect required or otherwise excepted data as a deviation from the rule will provide the necessary incentive to collect data sufficient to demonstrate compliance with the limits in the final rule.

Comment: Recordkeeping. Several commenters opposed the requirements related to maintaining records on site and for 5 years.

Response: We believe the recordkeeping and retention requirements are consistent with other requirements already in place, specifically 40 CFR 63.10 (b).

In addition, the 5-year retention period is the general rule for all recordkeeping for all sources under the part 70 operating permits program. Given that the General Provisions for 40 CFR part 63 and part 70 already establish a 5-year retention period, we believe it is justified in using those precedents for the retention periods under this subpart. If we stayed silent on retention period in this subpart, the General Provisions would provide for the 5-year retention as would the part 70 requirements. Thus, this action does not establish any new retention requirements, but merely confirms that the existing retention requirements apply.

Comment: Electronic Reporting. In the proposed rule, we requested comment on using ECMPS for reporting under this rule, as well as other options including the ERT. Commenters generally supported the use of ECMPS, especially for CEMS data. Some commenters requested an additional rulemaking on the specific data elements to be collected. There were some concerns raised about the ERT given experience during the 2010 ICR process during the development of this rule.

Response: We recognize that emissions reporting for continuously measured pollutants (SO_2, NO_X, etc.) and for periodically measured pollutants (PM, HAP metals, etc.) have different data demands. We recognize that minor revisions of the ECMPS will fulfill our data needs for most continuously measured pollutants and we will make these modifications for receipt of the additional CEMS data. We also recognize the need for substantial modifications to the ECMPS to accommodate the data needs for periodically measured pollutants and certain CEMS data such as PM CEMS data and possibly HAP metals CEMS data. Although major modifications of the ECMPS would be required for periodic compliance tests by isokinetic and instrumental test methods (as well as certain types of CEMS), only minor revisions are required of the ERT to receive these tests. We are implementing the changes in the ERT that are required to provide the software tools to implement the delivery of these performance test data to us.

The electronic submission of compliance test reports to us through the Central Data Exchange (CDX) is not solely for the purpose of developing improved emissions factors as some commenters assert. Although populating WebFIRE will allow us to improve emissions factors, we intend to use data stored in WebFIRE as the primary location for compliance test reports for use by regulatory authorities. The electronic submission of compliance test reports is a continuation of our efforts to bring the submission and sharing of environmental data into the modern age. The storage of this compliance data in our WebFIRE provides a convenient location which is already used to store source test data.

As federal and state and local agencies' data systems mature, information provided through the ERT will be used to populate these data systems. We are currently upgrading the AIRS Facility System and expect to replace manually entered information with electronic population from the ERT. We are also working with several state and local agencies to adopt the use of the ERT for delivery of compliance test reports. The ERT is also much improved since the version used during the 2010 ICR process, and there is no expectation that the information to be reported under this final rule will be as extensive as some of the data reported for the 2010 ICR purposes.

We disagree that a separate and independent regulatory action is required to implement electronic reporting for selected regulated sources. Each of these regulatory actions for selected source categories provides ample notice and the opportunity for individuals to provide comment. We also disagree that the system to receive the compliance data must be operational prior to establishing the requirement for regulated sources to submit compliance data electronically. We are on track to have the capability to receive electronic compliance tests through our CDX in sufficient time to receive all utility source test reports required by this final rule.

We do plan a separate and independent regulatory action to implement electronic reporting for regulated entities which are covered by past and future rules. Although we have provided draft procedures for the development of emissions factors, that effort is an ancillary effort to the electronic delivery of compliance test reports. It is our intention to convert to the electronic delivery and storage of all air emissions compliance source test data. With this transition, we believe this valuable information will be more readily available not only for compliance purposes but also for a variety of other uses.

I. Emissions Averaging

Comment: In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

Response: We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for EGUs at the affected source that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. See section VI of thie preamble for a fuller discussion.

J. LEE Criteria

Comment: A commenter supported the LEE provisions but believed one of the LEE eligibility criteria should set at 29.0 lb/year, rather than 22.0 lb/year. The commenter suggested 29.0 lb/year to be an equally reasonable cut point, especially since that value matches the low mass emitter Hg monitoring cutoff in CAMR and the low mass emitter Hg monitoring cutoff that several states have adopted, including Illinois, 35 Ill. Admin. Code section 225.240(a)(4). (*See, e.g.,* Colorado (5 Colo. Code Regs. section 1 00 1–8, Reg. No.6, part B, Section VIII.B.l0); Michigan (Mich. Admin. Code R. 336.2160); Montana (Mont. Admin. R. 17.8771(12))). Further, a LEE cutoff of 29.0 lb would eliminate conflicts and confusion with low mass emitter provisions in existing state Hg programs and significantly reduce compliance costs and burdens for the additional qualifying units without adversely affecting compliance assurance with the EGU NESHAP Hg emission limits or materially increasing the number of potential qualifying LEEs. Given the many other costly burdens that the rule would impose, the benefit of LEE to a qualifying unit is not insignificant.

Response: The Agency reviewed the commenter's suggestions, and one of the LEE eligibility criteria in the rule has been revised from 22.0 to 29.0 lb of Hg per year. The Agency finds the result of consistency with existing state regulations outweighs the two percent difference in nationwide Hg mass emissions, from 5 percent to 7 percent, for LEE eligibility.

VIII. Background Information on the NSPS

A. What is the statutory authority for this final NSPS?

New source performance standards implement CAA section 111(b), and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. Section 111 of the CAA requires that NSPS reflect the application of the best system of emissions reductions which (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. The level of control prescribed by CAA section 111 historically has been referred to as ''Best Demonstrated Technology'' or BDT. In order to better reflect that CAA section 111 was amended in 1990 to clarify that ''best systems'' may or may not be ''technology,'' the EPA is now using the term ''best system of emission reduction'' or BSER. As was done previously in analyzing BDT, the EPA uses available information and considers the emission reductions and incremental costs for different systems available at reasonable cost. Then, the EPA determines the appropriate emission limits representative of BSER. Section 111(b)(1)(B) of the CAA requires EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

B. What is the regulatory authority for the final rule?

The current standards for steam generating units are contained in the NSPS for EGUs (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc).

The NSPS for EGUs (40 CFR part 60, subpart Da) were originally promulgated on June 11, 1979 (44 FR 33580) and apply to units capable of firing more than 73 megawatts (MW) (250 MMBtu/h) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS for EGUs also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system. The most recent significant amendments to emission standards under 40 CFR part 60, subpart Da, were promulgated in 2006 (71 FR 9866) resulting in new PM, SO_2, and NOP_2 limitations for 40 CFR part 60, subpart Da units.

The NSPS for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db) apply to units for which construction, modification, or reconstruction commenced after June 19, 1984, that have a heat input capacity greater than 29 MW (100 MMBtu/h). Those standards were originally promulgated on November 25, 1986 (51 FR 42768) and also have been amended since the original promulgation to reflect changes in BSER for these sources.

The NSPS for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc) were originally promulgated on September 12, 1990 (55 FR 37674) and apply to units with a maximum heat input capacity greater than or equal to 2.9 MW (10 MMBtu/h) but less than 29 MW (100 MMBtu/h). Those standards apply to units that commenced construction, reconstruction, or modification after June 9, 1989.

IX. Summary of the Final NSPS

The final rule amends the emission standards for SO_2, NOP_2, and PM in 40 CFR part 60, subpart Da. Only those units that begin construction, modification, or reconstruction after May 3, 2011, will be affected by the final rule. Compliance with the emission limits of the final rule will be determined using testing, monitoring, and other compliance provisions similar to those set forth in the existing standards. In addition to the emissions limits contained in the final rule, we also are including several technical clarifications and corrections to existing provisions of the subparts.

A. What are the requirements for new EGUs (40 CFR part 60, subpart Da)?

The filterable PM emissions standard for new and reconstructed EGUs is 11 nanograms per joule (ng/J) (0.090 pound per megawatt hour (lb/MWh)) gross energy output regardless of the type of fuel burned. The PM emissions standard for modified EGUs is essentially equivalent to the existing requirements of 13 ng/J (0.015 lb/MWh) heat input regardless of the type of fuel burned. Compliance with this emission limit can be determined using testing, monitoring, and other compliance provisions similar to those for PM standards set forth in the existing rule. While not required, PM CEMS may be used as an alternative method to demonstrate continuous compliance and as an alternative to opacity and parameter monitoring requirements.

The SO_2 emission limit for new and reconstructed EGUs is 130 ng/J (1.0 lb/MWh) gross energy output or 97 percent reduction regardless of the type of fuel burned with one exception. The EPA neither proposed to amended the SO_2 standard for coal refuse-fired EGUs, not reopened the issue of whether coal refuse-fired EGUs is an appropriate subcategory, and, therefore, that emissions standard is unchanged. The SO_2 emission limit for modified EGUs burning any fuel is 180 ng/J (1.4 lb/MWh) gross energy output or 90 percent reduction. Compliance with the SO_2 emission limit is determined on a 30-boiler operating day rolling average basis using a CEMS to measure SO_2 emissions and following the compliance provisions in the proposed rule.

The NO_X emission limit for new and reconstructed EGUs is 88 ng/J (0.70 lb/MWh) gross energy output regardless of the type of fuel burned with one exception. The exception is that for new and reconstructed EGUs that burn over 75 percent coal refuse (by heat input), the NO_X emission limit is 110 ng/J (0.85 lb/MWh) gross energy output. The NO_X limit for modified EGUs is 140 ng/J (1.1 lb/MWh) gross energy output regardless of the type of fuel burned in the unit. Compliance with this emission limit is determined on a 30-boiler operating day rolling average basis using testing, monitoring, and other compliance provisions similar to those in the proposed rule.

As an alternative to the NO_X standard, owners/operators of new and reconstructed EGUs may elect to comply with a combined NO_X/CO standard of 140 ng/J (1.1 lb/MWh) with one exception. The exception is that for new and reconstructed EGUs that burn over 75 percent coal refuse (by heat input) on an annual basis, the NO_X/CO emission limit is 160 ng/J (1.3 lb/MWh) gross energy output. Finally, owners/operators of modified EGUs may elect to comply with a combined NO_X/CO standard of 190 ng/J (1.5 lb/MWh).

B. Additional Amendments

See the Response to Comments document.

X. Summary of Significant Changes Since Proposal

A. Emission Limits

The proposal included a combined (filterable plus condensable) PM standard. The final standard is based only on filterable PM. No standard is being established for condensable PM. The rationale for this is set forth in the Response to Comments (RTC) document for this final rule (the NSPS Final Rule RTC).

The proposal requested comment on whether the final standard should include a stand-alone NO_X standard or a combined NO_X/CO standard. In response to comments we received and our own further evaluation of the situation, the final standard includes a stand-alone NO_X standard and an optional, but not required, combined NO_X/CO standard as an alternative to the amended NO_X standard. Again, our full rationale for this is set forth in the NSPS Final Rule RTC. The proposal also included a request for comment on whether the standard should be based on gross or net output. In response to comments we received and our own further evaluation of the situation, the final standards are based on an amended definition of gross output with an optional net output-based standard. This too is addressed more fully in the NSPS Final Rule RTC.

The proposal included alternate emission standards for commercial demonstration projects. Proposed commercial demonstrations included pressurized fluidized beds, multi-pollutant control technologies, and advanced combustion controls. The final rule includes the commercial demonstration permit exemption for pressurized fluidized beds and multi-pollutant control technologies, but not advanced combustion controls. Advanced combustion controls are applicable to existing facilities and the exemption is not necessary to further the development of the technology.

B. Requirements During Startup, Shutdown, and Malfunction

For startup and shutdown, the requirements for PM have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards for PM in lieu of numeric emission limits. Emissions incurred during periods of startup and shutdown for PM are not used in demonstrations of compliance with the 30-boiler operating day rolling average period applicable for numeric emission standards.

XI. Public Comments and Responses to the Proposed NSPS

See the Response to Comments document.

XII. Impacts of the Final Rule

The EPA anticipates significant public health and environmental benefits from the rule as a direct result of the substantial reduction in the emissions of several pollutants, including SO_2, Hg, acid gases and fine particles and metals. For example, exposure to Hg can damage the developing nervous system, which can impair children's ability to think and learn, and fine particles can cause adverse cardiovascular effects. Further, reducing Hg deposition to ecosystems will benefit wildlife including fish, birds, and mammals. Fish and fish-eating birds, such as the common loon, and mammals suffer reproductive, survival, and behavioral impairments due to mercury exposure. These effects have also been observed in insect-eating and wading birds, including egrets and white ibis. Reductions of emissions targeted by this rule also will slow acidification and eutrophication of water bodies.

Additionally, the EPA anticipates significant non-health, non-ecological benefits from this rule. The fine particle and SO_2 emission reductions achieved by this rule will improve visibility, which is especially important for our national parks. Emissions reductions from this rule will also avoid an estimated $360 million (in $2007) of climate-related costs, such as agricultural productivity and property damage from increased flood risks.

A. What are the air impacts?

The EPA anticipates significant emission reductions under the final rule from coal-fired EGUs, which are of particular interest due to their share of total power sector emissions. In 2015, annual HCl emissions are projected to be reduced by 88 percent, Hg emissions reduced by 75 percent, and $PM_{2.5}$ emissions reduced by 19 percent from coal-fired EGUs greater than 25 MW. In addition, the EPA projects SO_2 emission reductions of 41 percent, and annual CO_2 reductions of 1 percent from coal-fired EGUs greater than 25 MW by 2015, relative to the base case. *See* Table 7.

TABLE 7—SUMMARY OF EMISSION REDUCTIONS FROM COAL-FIRED EGUS GREATER THAN 25 MW (TPY)

	SO_2 (million tons)	NO_X (million tons)	Mercury (tons)	HCl (thousand tons)	$PM_{2.5}$ (thousand tons)	CO_2 (million metric tonnes)
Base Case	3.3	1.7	27	45	270	1,906
MATS	1.9	1.7	7	6	218	1,882
Change	−1.4	0.0	−20	−40	−52	−23

Note: Numbers may not add due to rounding.

The reductions in this table do not account for reductions in other HAP which will occur as a result of this rule. For instance, the fine particulate reductions presented above only partly reflect reductions in many heavy metal particulates, and the HCl reductions above only partly reflect reductions of all acid gases. This rule will also result in additional HAP reductions from oil-fired EGUs, which are covered by the rule but are not included in the EPA's analysis of emission reductions.

B. What are the energy impacts?

The EPA projects that approximately 4.7 GW of coal-fired generation (less than 2 percent of all coal-fired capacity and 0.5 percent of total generation capacity in 2015) may be uneconomic to maintain and may be removed from operation by 2015. These units are predominantly smaller, less frequently used, and are dispersed throughout the country. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to make further investments in these facilities and keep these units operational.

The final rule has other important energy market implications. Average nationwide retail electricity prices are projected to increase in the contiguous U.S. by 3.1 percent in 2015. The average delivered coal price is projected to increase by less than 2 percent in 2015 as a result of shifts within and across coal types. The EPA also projects that electric power sector-delivered natural gas prices will increase by between 0.3 and 0.6 percent over the 2015 to 2030 timeframe, on average, and that natural gas use for electricity generation will increase by less than 200 billion cubic feet (BCF) in 2015. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 10 million tons in 2015 from base case levels, which is about 1 percent of total coal produced for the electric power sector in that year.

C. What are the cost impacts?

The power industry's ''compliance costs'' are represented in this analysis as the change in electric power generation costs between the base case and policy case in which the sector pursues pollution control approaches to meet the MATS emission standards. In simple terms, these costs are the resource costs of direct power industry expenditures to comply with the EPA's requirements.

The EPA projects that the annual incremental compliance cost of MATS is $9.6 billion in 2015 ($2007). The annualized incremental cost is the projected additional cost of complying with the rule in the year analyzed, and includes the amortized cost of capital investment and the ongoing costs of operating additional pollution controls, needed new capacity, shifts between or amongst various fuels, and other actions associated with compliance.

The total incremental compliance cost includes compliance costs modeled in IPM of $9.4 billion, costs modeled outside of IPM for oil-fired EGUs of $56 million, and monitoring, reporting, and recordkeeping costs of $158 million.

D. What are the economic impacts?

For this final rule, EPA analyzed the costs using the IPM. The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for a variety of HAP and other pollutants throughout the contiguous U.S. for the entire power system.

Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.*

The EPA performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (*e.g.*, sales and revenue tests). The EPA's analysis can be found in Chapter 7 of the RIA for this rule. The EPA has also prepared a Final Regulatory Flexibility Analysis (FRFA) that discusses alternative regulatory or policy options that minimize the rule's small entity impacts.

Although a stand-alone analysis of employment impacts is not included in a standard cost-benefit analysis, the current economic climate has led to heightened concerns about potential job impacts. Executive Order 13563 specifically states that our ''regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and *job creation*'' (emphasis added).

Under conditions of full employment, it is conventional to assume that regulations will merely shift jobs from one sector to another, without having a material effect on employment levels. Potential employment effects are of greater concern in the current economic climate, with high levels of employment, because of the risk that displaced workers may not find alternative jobs. In addition, regulations that result in firms hiring workers, in order to ensure compliance, may have a positive effect on employment.

During sustained periods of excess unemployment, the opportunity cost of labor required by regulated sectors to bring their facilities into compliance with an environmental regulation may be lower than it would be during a period of full employment (particularly if regulated industries employ otherwise idled labor to design, fabricate, or install the pollution control equipment required under this final rule). Consistent with EO 13563, the EPA includes estimates of job impacts associated with the final rule. In the electricity sector, the EPA estimates that the net employment effect will range from −15,000 to +30,000 jobs, with a central estimate of +8,000. The EPA also presents an estimate of short-term employment effects as a result of increased demand for pollution control equipment.

The results of this analysis, found in Chapter 6 of the RIA, indicate that the final rule has the potential to provide increases in short-term employment in the environmental industry, primarily driven by the high demand for new pollution control equipment. Overall, the results suggest that the final rule could support a net of roughly 46,000 job years [355] in direct employment impacts in 2015.

There are other employment effects that cannot be estimated quantitatively at this time. The employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements. On the other hand, some of those workers who lose their jobs due to plant retirements could find alternative employment operating the replacement electricity generating equipment or new pollution controls at nearby units. Finally, job losses due to reduced coal demand may be offset by job gains due to increased natural gas demand, potentially resulting in a positive net change in employment due to fuel demand changes.

The basic approach to estimate these employment impacts involved using IPM projections from the final rule analysis, in particular the amount of existing coal-fired capacity that is projected to be retrofit with pollution control technologies. These data, along with data on labor and resource needs of new pollution controls and labor productivity from engineering studies and secondary sources, are used to estimate employment impacts for the pollution control industry in 2015. For more information, please refer to Chapter 6 and appendix 6B in the RIA.

The EPA relied on Morgenstern, *et al.,* (2002), to identify three economic mechanisms by which pollution abatement activities can influence jobs in the regulated sector separately from the short-term employment effects:

- Higher production costs raise market prices, higher prices reduce consumption, and employment within an industry falls (''demand effect'');
- Pollution abatement activities require additional labor services to produce the same level of output (''cost effect''); and
- Post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output) (''factor-shift effect'').

Using plant-level Census information between the years 1979 and 1991,

[355] Numbers of job years are not the same as numbers of individual jobs, but represents the amount of work that can be performed by the equivalent of one full-time individual for a year (or FTE). For example, 25 job years may be equivalent to five full-time workers for five years, 25 full-time workers for one year, or one full-time worker for 25 years.

Morgenstern,*et al.,* estimate the size of each effect for four polluting and regulated industries (petroleum, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million spent on pollution abatement results in a small net increase of 1.55 jobs; the estimated effect is not a statistically different from zero. As a result, the authors conclude that increases in pollution abatement expenditures may increase employment in the relevant sectors and do not necessarily cause economically significant employment changes. The conclusion is similar to that of Berman and Bui (2001) who found that increased air quality regulation in Los Angeles did not cause large employment changes.[356] For more information, please refer to Chapter 6 of the RIA for this final rule.[357]

In the directly affected sector, the EPA estimates that the net employment effect will range from −15,000 to +30,000 jobs, with a central estimate of +8,000. The ranges of job effects for the electricity sector, as calculated using the Morgenstern,*et al.,* approach are listed in Table 8.

TABLE 8—RANGE OF JOB EFFECTS FOR THE ELECTRICITY SECTOR

	Estimates using Morgenstern, *et al.,* (2001)			
	Demand effect	Cost effect	Factor shift effect	Net effect
Change in Full-Time Jobs per Million Dollars of Environmental Expenditure [a].	−3.56	2.42	2.68	1.55.
Standard Error	2.03	0.83	1.35	2.24.
EPA estimate for Final Rule [b]	−39,000 to +2,000	+4,000 to +21,000	+200 to +27,000	−15,000 to +30,000.

[a] Expressed in 1987 dollars. *See* footnote a from Table 6–2 of the RIA for inflation adjustment factor used in the analysis.
[b] According to the 2007 Economic Census, the electric power generation, transmission and distribution sector (NAICS 2211) had approximately 510,000 paid employees.

The EPA recognizes there may be other job effects that are not considered in the Morgenstern,*et al.,* study. Although EPA has considered some economy-wide changes, we do not have sufficient information to quantify other job effects associated with this rule.

E. What are the benefits of this final rule?

1. Benefits of Reducing HAP Emissions

a. Human Health and Environmental Effects Due to Exposure to MeHg. In this section, we provide a qualitative description of human health and environmental effects due to exposure to MeHg. The NAS Study (NRC, 2000) provides a thorough review of the effects of MeHg on human health. Many of the peer-reviewed articles cited in this section are publications originally cited in the NAS Study. In addition, the EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NAS in 2000.

b. Neurologic Effects of Exposure to MeHg. In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and concluded that they are appropriate for establishing an RfD (NRC, 2000); in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS Study (NRC, 2000) noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS noted that their recommended neurodevelopmental endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: ''The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school.''

c. Cardiovascular Impacts of Exposure to MeHg. The NAS summarized data on cardiovascular effects available up to 2000. Based on these and other studies, the NAS Study concluded that ''Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.*, neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals.'' The report also stated that ''additional studies are needed to better characterize the effect of MeHg exposure on blood pressure and cardiovascular function at various stages of life.''

Additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

d. Genotoxic Effects of Exposure to MeHg. The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS Study indicated that evidence that human exposure to MeHg causes genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajós River region in Brazil (Amorim*et al.,* 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes, as well as effects on chromosomes. Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those

[356] For alternative views in economic journals, see Henderson (1996) and Greenstone (2002).

[357] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

seen in the populations studied in the Faroe Islands and Republic of Seychelles.

e. Immunotoxic Effects to Exposure to MeHg. Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000).

f. Other Hg-Related Human Toxicity Data. Based on limited human and animal data, MeHg is classified as a ''possible'' human carcinogen by the International Agency for Research on Cancer (IARC, 1994) and in IRIS (USEPA, 2002). The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of cancer incidence (*e.g.,* acute leukemia and liver cancer) (NAS, 2000).

Some evidence of reproductive and renal toxicity in humans from MeHg exposure exists. However, overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

g. Ecological Effects of Hg. Deposition of Hg to watersheds can also have an impact on ecosystems and wildlife. Mercury contamination is present in all environmental media, with aquatic systems experiencing the greatest exposures due to bioaccumulation. Bioaccumulation refers to the net uptake of a contaminant from all possible pathways and includes the accumulation that may occur by direct exposure to contaminated media as well as uptake from food.

A review of the literature on effects of Hg on fish [358] reports results for numerous species including trout, bass (large and smallmouth), northern pike, carp, walleye, salmon, and others from laboratory and field studies. The effects of MeHg in fish are reproductive in nature. Although we cannot determine at this time whether these reproductive deficits are affecting fish populations across the U.S. it should be noted that it would seem reasonable that over time reproductive deficits would have an effect on populations.

Mercury also affects avian species. In previous reports [359] much of the focus has been on large piscivorous species, in particular the common loon. According to Evers,*et al.,* significant adverse effects from Hg on breeding loons have been found to occur, including behavioral (reduced nest-sitting), physiological (flight feather asymmetry) and reproductive (chicks fledged/territorial pair) effects and reduced survival.[360] Additionally, Evers, *et al.,* (*see* footnote 5), believe that the weight of evidence indicates that population-level effects occur in parts of Maine and New Hampshire, and potentially in broad areas of the loon's range.

Recently, attention has turned to other piscivorous species such as the white ibis and great snowy egret. These wading birds have a very wide diet including crayfish, crabs, snails, insects and frogs. White ibis have been observed to have decreased foraging efficiency[361] and have been shown to exhibit decreased reproductive success and altered pair behavior.[362] In egrets, Hg has been implicated in the decline of the species in south Florida,[363] and Hoffman[364] has shown that egrets exhibit liver and possibly kidney effects. Although ibises and egrets are most abundant in coastal areas and these studies were conducted in south Florida and Nevada, the ranges of ibises and egrets extend to a large portion of the U.S.

Insectivorous birds have also been shown to suffer adverse effects due to Hg exposure. Songbirds such as Bicknell's thrush, tree swallows, and the great tit have shown reduced reproduction, survival, and changes in singing behavior. Exposed tree swallows produced fewer fledglings,[365] had lower survival rates,[366] and had compromised immune competence.[367] The great tit has exhibited reduced singing behavior and smaller song repertoire in areas of high contamination.[368]

In mammals, adverse effects have been observed in mink and river otter, both fish eating species. For otter from Maine and Vermont, maximum concentrations of Hg in fur nearly equal or exceed a level associated with mortality and concentration in liver for mink in Massachusetts/Connecticut and the levels in fur from mink in Maine exceed concentrations associated with acute mortality.[369] Adverse sublethal effects may be associated with lower Hg concentrations and consequently may be more widespread than potential acute effects. These effects may include increased activity, poorer maze performance, abnormal startle reflex, and impaired escape and avoidance behavior.[370]

h. Methodology for Partial Hg Benefits Estimation. The EPA has conducted a national-scale analysis of the benefits to recreational anglers of avoided IQ loss related to reductions of Hg emissions

[358] Crump, KL, and Trudeau, VL. Mercury-induced reproductive impairment in fish. Environmental Toxicology and Chemistry. Vol. 28, No. 5, 2009.

[359] U.S. Environmental Protection Agency (EPA). 1997. Mercury Study Report to Congress. Volume V: Health Effects of Mercury and Mercury Compounds. EPA–452/R–97–007. U.S. EPA Office of Air Quality Planning and Standards, and Office of Research and Development; U.S. Environmental Protection Agency (U.S. EPA). 2005. *Regulatory Impact Analysis of the Final Clean Air Mercury Rule.* Research Triangle Park, NC., March; EPA report no. EPA–452/R–05–003. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/mercury_ria_final.pdf.*

[360] Evers, DC, Savoy, LJ, DeSorbo, CR, Yates, DE, Hanson, W, Taylor, KM, Siegel, LS, Cooley, JH, Jr., Bank, MS, Major, A, Munney, K, Mower, BF, Vogel, HS, Schoch, N, Pokras, M, Goodale, MW, Fair, J. Adverse effects from environmental mercury loads on breeding common loons. Ecotoxicology. 17:69–81, 2008; Mitro, MG, Evers, DC, Meyer, MW, and Piper, WH. Common loon survival rates and mercury in New England and Wisconsin. Journal of Wildlife Management. 72(3): 665–673, 2008.

[361] Adams, EM, and Frederick, PC. Effects of methylmercury and spatial complexity on foraging behavior and foraging efficiency in juvenile white ibises (Eudocimus albus). Environmental Toxicology and Chemistry. Vol 27, No. 8, 2008.

[362] Frederick, P, and Jayasena, N. Altered pairing behavior and reproductive success in white ibises exposed to environmentally relevant concentrations of methylmercury. Proceedings of The Royal Society B. doi: 10–1098, 2010.

[363] Sepulveda, MS, Frederick, PC, Spalding, MG, and Williams, GE, Jr. Mercury contamination in free-ranging great egret nestlings (Ardea albus) from southern Florida, USA. Environmental Toxicology and Chemistry. Vol. 18, No. 5, 1999.

[364] Hoffman, DJ, Henny, CJ, Hill, EF, Grover, RA, Kaiser, JL, Stebbins, KR. Mercury and drought along the lower Carson River, Nevada: III. Effects on blood and organ biochemistry and histopathology of snowy egrets and black-crowned night-herons on Lahontan Reservoir, 2002–2006. Journal of Toxicology and Environmental Health, Part A. 72: 20, 1223–1241, 2009.

[365] Brasso, RL, and Cristol, DA. Effects of mercury exposure in the reproductive success of tree swallows (Tachycineta bicolor). Ecotoxicology. 17:133–141, 2008.

[366] Hallinger, KK, Cornell, KL, Brasso, RL, and Cristol, DA. Mercury exposure and survival in free-living tree swallows (Tachycineta bicolor). Ecotoxicology. Doi: 10.1007/s10646–010–0554–4, 2010.

[367] Hawley, DM, Hallinger, KK, Cristol, DA. Compromised immune competence in free-living tree swallows exposed to mercury. Ecotoxicology. 18:499–503, 2009.

[368] Gorissen, L, Snoeijs, T, Van Duyse, E, and Eens, M. Heavy metal pollution affects dawn singing behavior in a small passerine bird. Oecologia. 145: 540–509, 2005.

[369] Yates, DE, Mayack, DT, Munney, K, Evers DC, Major, A, Kaur, T, and Taylor, RJ. Mercury levels in mink (Mustela vison) and river otter (Lonra canadensis) from northeastern North America. Ecotoxicology. 14, 263–274, 2005.

[370] Scheuhammer, AM, Meyer MW, Sandheinrich, MB, and Murray, MW. Effects of environmental methylmercury on the health of wild birds, mammals, and fish. Ambio. Vol.36, No.1, 2007.

and subsequent deposition that will be achieved by this rule. Because the primary measurable health effect of concern—developmental neurological abnormalities in children—occurs as a result of in-utero exposures to Hg, the specific population of interest in this case is prenatally exposed children. To identify and estimate the size of this exposed population, the benefits analysis focused on pregnant women in freshwater recreational angler households. Estimating Hg exposures for this exposure pathway and population of interest requires three main components: (1) The size of the exposed population of interest (annual number of pregnant women in freshwater angler households during the year), (2) the average concentration of MeHg in noncommercial freshwater fish filets consumed, and (3) the average daily consumption rate of noncommercial freshwater fish. The Hg concentrations of fish in the waterbodies where the fish are caught are modeled using Mercury Maps to project the decline in concentrations due to the rule. To approximate the percentage of freshwater fishing trips (and exposed individuals) from each Census tract matched to each waterbody type, the EPA used state-level averages. These averages were calculated for each state, based on the portion of residents' freshwater fishing trips that are to each waterbody type, based on 2001 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation (FHWAR) data.

Data from the 1994 National Survey on Recreation and the Environment (NSRE) were used to approximate the percentage of freshwater fishing trips (and exposed individuals) matched to different distances from anglers' residential location.

To determine an appropriate daily fish consumption rate for the analysis, the EPA conducted an extensive review of existing literature characterizing self-caught freshwater fish consumption. Based on this review, it was decided that the ingestion rates for recreational freshwater fishers, specified as ''recommended'' in the EPA's ''Environmental Exposure Factors Handbook'' (EPA, 1997), represented the most appropriate values to use in this analysis.

Estimating the IQ decrements in children that result from mothers' prenatal ingestion of Hg from fish required two steps. First, based on the estimated average daily maternal ingestion rate, the expected Hg concentration in the hair of exposed pregnant women was estimated. Second, to estimate the expected IQ decrement in offspring, the following dose-response relationship was developed based on the summary findings reported in Axelrad *et al.,* (2007).

The valuation approach used to assess monetary losses due to IQ decrements is based on an approach applied in previous EPA analyses (EPA, 2008). The approach expresses the potential loss to an affected individual resulting from IQ decrements in terms of foregone future earnings (net of changes in education costs) for that individual.

The estimate for ''Present Value of Lifetime Earnings'' is derived using earnings and labor force participation rate data from the Bureau of Labor Statistics 2006 Current Population Survey. Estimates of the average effect of a 1-point increase in IQ on lifetime earnings range from a 1.76 percent increase (Schwartz, 1994) to a 2.379 percent increase (Salkever, 1995). The percentage increases in the two studies reflect both the direct impact of IQ on hourly wages and indirect effects on annual earnings as the result of additional schooling and increased labor force participation. The estimate for years of additional schooling is based on Schwartz (1994), who reports an increase of 0.131 years of schooling per IQ point.

In addition to this positive net effect on earnings, an increase in IQ is also assumed to have a positive effect on the amount of time spent in school and on associated costs. To incorporate (1) uncertainty regarding the size of the percentage change in future earnings and (2) different assumptions regarding the discount rate, the resulting value estimates for the average net loss per IQ point decrement are expressed as a range. Assuming a 3 percent discount rate, value IQ ranges from $8,013 (using the Schwartz estimates) to $11,859 (using the Salkever estimates) in increased earnings per year per 1-point IQ increase. With a 7 percent discount rate assumption, the value IQ estimates range from $893 to $1,958 in increased earnings per year per 1-point IQ increase.

The EPA analyzed the aggregate national IQ and present-value loss estimates for two base case and three emission control scenarios. The highest losses are estimated for the 2005 base case. For the population of prenatally exposed children included in the analysis (almost 240,000), Hg exposures under baseline conditions during the year 2005 are estimated to have resulted in more than 25,500 IQ points lost. Assuming a 3 percent discount rate, the present-year value of these losses ranges from $204.8 million to $292.5 million nationally.[371] These losses represent expected present value of declines in future net earnings over the entire lifetimes of the children who are prenatally exposed during the year 2005. With a 7 percent discount rate, the present-year value range is considerably lower: $22.8 million to $50.0 million.

For this rule, the EPA generated estimates of aggregate nationwide benefits associated with reductions in Hg exposures and resulting reductions in IQ losses. Most importantly, the benefits of the 2016 MATS scenario (relative to the 2016 base case) are estimated to range between $4 million and $6 million (assuming a 3 percent discount rate), because of an estimated 511 point reduction in IQ losses. The EPA recognizes that these calculated benefits are a small subset of the benefits of reducing Hg emissions.

2. Health and Welfare Co-Benefits

Emission controls installed to meet the requirements of this rule will generate co-benefits by reducing criteria pollutants including $PM_{2.5}$ and SO_2, as well as CO_2. For this rule, we were only able to estimate the mortality benefits of $PM_{2.5}$ reductions due to changes in emissions of SO_2 and direct $PM_{2.5}$ and climate benefits resulting from CO_2 reductions. Additional co-benefits may result from decreases in $PM_{2.5}$ morbidity impacts, decreases in sulfur deposition and direct health effects of SO_2, and improvements in visibility in national parks and wilderness areas. Total co-benefits may be higher than the partial estimates of co-benefits provided here. Our best estimate of the monetized health and climate co-benefits of this rule in 2016 at a 3 percent discount rate are $37 billion to $90 billion or $33 billion to $81 billion at a 7 percent discount rate (2007$). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower health co-benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[372]

a. Human Health Co-Benefits. To estimate the human health co-benefits of this rule, the EPA used benefit-per-ton

[371] Monetized benefits estimates are for an immediate change in MeHg levels in fish. If a lag in the response of MeHg levels in fish were assumed, the monetized benefits could be significantly lower, depending on the length of the lag and the discount rate used. As noted in the discussion of the Mercury Maps modeling, the relationship between deposition and fish tissue MeHg is proportional in equilibrium, but the Mercury Maps approach does not provide any information on the time lag of response.

[372] Roman, *et al.,* 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

factors to quantify the changes in $PM_{2.5}$-related health impacts and monetized benefits based on changes in SO_2 and direct $PM_{2.5}$ emissions. These benefit-per-ton factors were based on an interim baseline and policy scenario for which full-scale ambient air quality modeling and air quality-based human health benefits assessments were performed. This general approach and methodology is laid out in Fann, *et al.,* (2009),[373] but for this rule the air quality modeling used a better spatial representation of the emission changes from EGUs. Using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. For more details on the creation of the benefit-per-ton factors and their application to emission reductions under this rule, please refer to the RIA for this rule in the docket.

Table 9 presents the estimates of reduced annual incidence of $PM_{2.5}$-related health effects in 2016 resulting from this rule. Table 10 presents the estimated annual monetary value of the reduced incidence of quantified health endpoints in 2016 resulting from this rule.

The reduction in premature fatalities each year accounts for between 93 and 97 percent of the estimated health co-benefits that were monetized.

TABLE 9—ESTIMATED REDUCTIONS IN INCIDENCE OF $PM_{2.5}$-RELATED HEALTH EFFECTS IN 2016 [a]

Health effect	Number of reduced cases
Adult Premature Mortality	
Pope *et al.,* (2002) (age >30)	4,200. (1,200 to 7,200).
Laden *et al.,* (2006) (age >25)	11,000. (5,000 to 17,000).
Infant Premature Mortality (<1 year)	20. (−22 to 61).
Chronic Bronchitis	2,800. (88 to 5,600).
Non-fatal heart attacks (age >18)	4,700. (1,200 to 8,300).
Hospital admissions—respiratory (all ages)	830. (330 to 1,300).
Hospital admissions—cardiovascular (age >18)	1,800. (1,200 to 2,200).
Emergency room visits for asthma (age <18)	3,100. (1,600 to 4,700).
Acute bronchitis (age 8–12)	6,300. (−1,400 to 14,000).
Lower respiratory symptoms (age 7–14)	80,000. (31,000 to 130,000).
Upper respiratory symptoms (asthmatics age 9–11)	60,000. (11,000 to 110,000).
Asthma exacerbation (asthmatics 6–18)	130,000. (4,500 to 450,000).
Lost work days (ages 18–65)	540,000. (460,000 to 620,000).
Minor restricted-activity days (ages 18–65)	3,200,000. (2,600,000 to 3,800,000).

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

TABLE 10—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS IN 2016 [a]

Health effect	Monetized benefits
Adult Premature Mortality	
Pope, *et al.,* (2002) (age >30):	
3% discount rate	$34. ($2.6 to $100).
7% discount rate	$30. ($2.4 to $92).
Laden, *et al.,* (2006) (age >25):	
3% discount rate	$87. ($7.5 to $250).
7% discount rate	$78. ($6.8 to $230).
Infant Premature Mortality (<1 year)	$0.2. ($−0.2 to $0.8).
Chronic Bronchitis	$1.4. ($0.1 to $6.4).
Non-fatal heart attacks (age >18):	

[373] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." Air Qual Atmos Health (2009) 2:169–176.

TABLE 10—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS IN 2016 [a]—Continued

Health effect	Monetized benefits
3% discount rate	$0.5. ($0.1 to $1.3).
7% discount rate	$0.4. ($0.1 to $1.0).
Hospital admissions—respiratory (all ages)	$0.01. ($0.01 to $0.02).
Hospital admissions—cardiovascular (age >18)	$0.03. (<$0.01 to $0.05).
Emergency room visits for asthma (age <18)	<$0.01.
Acute bronchitis (age 8–12)	<$0.01.
Lower respiratory symptoms (age 7–14)	<$0.01.
Upper respiratory symptoms (asthmatics age 9–11)	<$0.01.
Asthma exacerbation (asthmatics 6–18)	<$0.01.
Lost work days (ages 18–65)	$0.1. ($0.1 to $0.1).
Minor restricted-activity days (ages 18–65)	$0.2. ($0.1 to $0.3).
Monetized Health Co-Benefits	
Pope, *et al.,* (2002):	
3% discount rate	$36. ($2.8–$110).
7% discount rate	$33. ($2.5–$100).
Laden, *et al.,* (2006):	
3% discount rate	$89. ($7.7–$260).
7% discount rate	$80. ($6.9–$240).

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

It is important to note that the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration response function for premature mortality. Experts have advised the EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. We cite two key empirical studies, one based on the American Cancer Society cohort study [374] and the other based on the extended Six Cities cohort study.[375] The analyses upon which this rule is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects, or to assign economic values even to those health and environmental outcomes that can be quantified. The uncertainties in the underlying scientific and economics literature (that may result in overestimation or underestimation of the co-benefits) are discussed in detail in the RIA. Despite these uncertainties, we believe the benefit analysis for this rule provides a reasonable indication of the expected health co-benefits of the rulemaking in future years under a set of reasonable assumptions.

When characterizing uncertainty in the PM-mortality relationship, the EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, the EPA's 2009 Integrated Science Assessment for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship.

In the RIA accompanying this rulemaking, rather than segmenting out impacts predicted to be associated with levels above and below a ''bright line'' threshold, the EPA includes a ''lowest measured level'' (LML) analysis that illustrates the increasing uncertainty that characterizes exposure attributed to levels of $PM_{2.5}$ below the LML of each epidemiological study used to estimate $PM_{2.5}$-related premature death. Figures provided in the RIA show the distribution of baseline exposure to $PM_{2.5}$, as well as the lowest air quality levels measured in each of the epidemiology cohort studies. This information provides a context for considering the likely portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction in $PM_{2.5}$-related premature mortality diminishes as baseline concentrations of $PM_{2.5}$ are lowered.

Based on the modeled interim baseline which is approximately equivalent to the final baseline (*see* Appendix A of the RIA), 11 percent and 73 percent of the estimated avoided mortality impacts occur at or above an

[374] Pope *et al.,* 2002. ''Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution.'' Journal of the American Medical Association. 287:1132–1141.

[375] Laden*et al.,* 2006. ''Reduction in Fine Particulate Air Pollution and Mortality.'' American Journal of Respiratory and Critical Care Medicine. 173:667–672.

annual mean $PM_{2.5}$ level of 10 µg/m3 (the LML of the Laden*et al.,* 2006 study)or 7.5 µg/m3 (the LML of the Pope,*et al.,* 2002 study), respectively. Although the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, the EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations. A large fraction of the $PM_{2.5}$-related benefits occur below the level of the National Ambient Air Quality Standard (NAAQS) for $PM_{2.5}$ at 15 µg/m3, which was set in 2006. It is important to emphasize that NAAQS are not set at a level of zero risk. Instead, the NAAQS reflect the level determined by the Administrator to be protective of public health within an adequate margin of safety, taking into consideration effects on susceptible populations. While benefits occurring below the standard may be less certain than those occurring above the standard, EPA considers them to be legitimate components of the total benefits estimate.

It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope, *et al.,* (2002), to Laden, *et al.,* (2006). These studies assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between directly-emitted particles (carbonaceous and crustal particles) and SO_2 emissions that form sulfate particles, based on the location of emission changes and magnitude of population exposure changes. Regardless, however, the assumption that all fine particles are equally potent in causing premature mortality adds uncertainty to the benefits estimate.

b. Non-Climate Welfare Co-Benefits. Emission controls installed to comply with the requirements specified in this rule will also generate co-benefits by improving visibility. We anticipate that improvements in visibility in Class I areas as well as residential areas where people live, work, and recreate could be substantial. Because full-scale air quality modeling was not performed for this rule, we are unable to quantify these visibility co-benefits for this rule. However, the estimated value of visibility benefits calculated from the modeled interim baseline and policy scenario was $1.1 billion (in 2007$). These visibility benefits are not included in the total co-benefits estimate of the final policy scenario used as a basis for this final rule. The distribution of emission reductions did not change substantially in the visibility regions studied, therefore visibility benefits of the final policy scenario are likely to be of a similar magnitude.

Ecosystem and other welfare effects include reduced acidification and, in the case of NO_X, eutrophication of water bodies; possible reduced nitrate contamination of drinking water; ozone vegetation damage; a reduction in the role of sulfate in Hg methylation; and reduced acid and particulate deposition that causes damages to cultural monuments, as well as soiling and other materials damage. To illustrate the important nature of benefit categories the EPA is currently unable to monetize, we discuss the potential public welfare and environmental impacts related to reductions in emissions required by this rule in the RIA, including reduced visibility impairment, reduced effects from acid deposition, reduced effects from nutrient enrichment, and reduced vegetation effects from ambient exposure to SO_2 and NO_2.

c. Climate co-benefits. This rule is expected to reduce CO_2 emissions from the electricity sector. The EPA has assigned a dollar value to reductions in CO_2 emissions using recent estimates of the ''social cost of carbon'' (SCC). The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year or the per metric ton benefit estimate relating to decreases in CO_2 emissions. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damage from increased flood risk, and the value of ecosystem services due to climate change.

The SCC estimates used in this analysis were developed through an interagency process that included the EPA and other executive branch entities, and that concluded in February 2010. We first used these SCC estimates in the benefits analysis for the final joint EPA/DOT Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; see the rule's preamble for discussion about application of the SCC (75 FR 25324; May 7, 2010). The SCC Technical Support Document (SCC TSD) provides a complete discussion of the methods used to develop these SCC estimates.[376]

The interagency group selected four SCC values for use in regulatory analyses, which we have applied in this analysis: $5.9, $24.3, $39, and $74.4 per metric ton of CO_2 emissions in 2016, in 2007 dollars. The first three values are based on the average SCC from three integrated assessment models, at discount rates of 5, 3, and 2.5 percent, respectively. Social cost of carbon values at several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the SCC from all three values at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the extremes of the SCC distribution. Low probability, high impact events are incorporated into all of the SCC values through explicit consideration of their effects in two of the three values as well as the use of a probability density function for equilibrium climate sensitivity. Treating climate sensitivity probabilistically results in more high temperature outcomes, which in turn leads to higher projections of damages.

Applying the global SCC estimates using a 3 percent discount rate, we estimate the value of the climate related benefits of this rule in 2016 is $360 million (2007$), as shown in Table 11. See the RIA for more detail on the methodology used to calculate these benefits and additional estimates of climate benefits using different discount rates and the 95th percentile of the 3 percent discount rate SCC. Important limitations and uncertainties of the SCC approach are also described in the RIA.

[376] Docket ID EPA–HQ–OAR–2009–0472–114577, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at *http://epa.gov/otaq/climate/regulations.htm.*

TABLE 11—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS AND CLIMATE BENEFITS IN 2016[a]

Effect	Monetized benefits
Monetized Health Co-Benefits	
Pope, *et al.,* (2002):	
3% discount rate	$36 ($2.8–$110)
7% discount rate	$33 ($2.5–$100)
Laden, *et al.,* (2006):	
3% discount rate	$89 ($7.7–$260)
7% discount rate	$80 ($6.9–$240)
Climate-related Co-Benefits (3% discount rate)	$0.36
Monetized Total Co-Benefits	
Pope, *et al.,* (2002):	
3% discount rate	$37 ($3.2–$110)
7% discount rate	$33 ($2.9–$100)
Laden, *et al.,* (2006):	
3% discount rate	$90 ($8.0–$260)
7% discount rate	$81 ($7.3–$240)

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

Our best estimate for the monetized total health and climate co-benefits of this rule in 2016 at a 3 percent discount rate is between $37 billion and $90 billion or between $33 billion and $81 billion (2007$) at a 7 percent discount rate. These estimates account for the quantified health and climate benefits described in Table 11.

XIII. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under EO 12866 (58 FR 51735; October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to 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. Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 and any changes in response to OMB recommendations have been documented in the docket for this action. For more information on the costs and benefits for this rule, please refer to Table 2 of this preamble.

When estimating the human health benefits and compliance costs in Table 2 of this preamble, the EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. The EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. In doing what is laid out above in this paragraph, the EPA adheres to EO 13563, ''Improving Regulation and Regulatory Review,'' (76 FR 3821; January 18, 2011), which is a supplement to EO 12866.

In addition to estimating costs and benefits, EO 13563 focuses on the importance of a ''regulatory system [that] * * * promote[s] predictability and reduce[s] uncertainty'' and that ''identify[ies] and use[s] the best, most innovative, and least burdensome tools for achieving regulatory ends.'' In addition, EO 13563 states that ''[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.'' We recognize that the utility sector faces a variety of requirements, including ones under CAA section 110(a)(2)(D) dealing with the interstate transport of emissions contributing to ozone and PM air quality problems, with coal combustion wastes, and with the implementation of CWA section 316(b). In developing today's final rule, the EPA recognizes that it needs to approach these rulemakings 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 underlie the rulemakings.

A summary of the monetized costs, benefits, and net benefits for the final rule at discount rates of 3 percent and 7 percent is in Table 2 of this preamble. For more information on the analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the 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 2137.06.

The information collection requirements are not enforceable until OMB approves them. The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These 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. This final rule requires maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 63, subpart UUUUU. 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 in 40 CFR 63.2 (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.

For this rule, EPA is adding affirmative defense to the estimate of burden in the ICR. 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 provided administrative adjustments to this ICR that shows 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 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.

For this reason, we estimate no more than two such occurrences for all sources subject to 40 CFR part 63, subpart UUUUU 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 monitoring, reporting, and record-keeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $207.6 million. This includes 700,296 labor hours per year at a total labor cost of $49.1 million per year, annualized capital costs of $81.9 million, and annual operating and maintenance costs of $76.5 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications, and recordkeeping. All burden estimates are in 2007 dollars and represent the most cost effective monitoring approach for affected facilities. 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 our regulations are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act, as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 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 today's rule on small entities, small entity is defined as: (1) A small business that is an electric utility producing 4 billion kilowatt-hours or less as defined by NAICS codes 221122 (fossil fuel-fired electric utility steam generating units) and 921150 (fossil fuel-fired electric utility steam generating units in Indian country); (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.

Pursuant to RFA section 603, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel to obtain advice and recommendations of representatives of the regulated small entities. A detailed discussion of the Panel's advice and recommendations is found in the Panel Report (EPA–HQ–OAR–2009–0234–2921). A summary of the Panel's recommendations is presented at 76 FR 24975.

As required by RFA section 604, we also prepared a final regulatory flexibility analysis (FRFA) for the final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA is summarized below and in the RIA.

1. Reasons Why Action Is Being Taken

In 2000, the EPA made a finding that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and listed EGUs pursuant to CAA section 112(c). On March 29, 2005 (70 FR 15994), the EPA published a final rule (2005 Action) that removed EGUs from the list of sources for which regulation under CAA section 112 was required. That rule was published in conjunction with a rule requiring reductions in emissions of Hg from EGUs pursuant to CAA section 111, i.e., CAMR, May 18, 2005, 70 FR 28606). The 2005 Action was vacated on February 8, 2008, by the U.S. Court of Appeals for the District of Columbia Circuit. As a result of that vacatur, CAMR was also vacated and EGUs remain on the list of sources that must be regulated under CAA section 112. This action provides the EPA's final NESHAP and NSPS for EGUs.

2. Statement of Objectives and Legal Basis for Final Rules

The MATS will protect air quality and promote public health by reducing emissions of HAP. In the December 2000 regulatory determination, the EPA made a finding that it was appropriate and necessary to regulate EGUs under CAA section 112. The February 2008 vacatur of the 2005 Action reverted the status of the rule to the December 2000 regulatory determination. Section 112(n)(1)(A) of the CAA and the 2000 determination do not differentiate between EGUs located at major versus area sources of HAP. Thus, the NESHAP for EGUs will regulate units at both major and area sources. Major sources of HAP are those that have the potential to emit at least 10 tons per year (tpy) of any one HAP or at least 25 tpy of any combination of HAP. Area sources are any stationary sources of HAP that are not major sources.

3. Summary of Issues Raised During the Public Comment Process on the IRFA

The EPA received a number of comments related to the Regulatory Flexibility Act during the public comment process. A consolidated version of the comments received is reproduced below. These comments can also be found in their entirety in the response to comment document in the docket.

Comment: Several commenters expressed concern with the SBAR panel. Some believe Small Entity Representatives (SERs) were not provided with regulatory alternatives including descriptions of significant regulatory options, differing timetables, or simplifications of compliance and reporting requirements, and subsequently were not presented with an opportunity to respond. One commenter believes the EPA's formal SBAR Panel notification and subsequent information provided by the EPA to the Panel did not include information on the potential impacts of the rule as required by CAA section 609(b)(1). Additional commenters suggested that the EPA's rulemaking schedule put pressure on the SBAR Panel through the abbreviated preparation for the Panel. Commenters also expressed concerns that the EPA did not provide participants more than cursory background information on which to base their comments. One commenter stated that the EPA did not provide deliberative materials, including draft proposed rules or discussions of regulatory alternatives, to the SBAR Panel members. One commenter stated the SBAR Panel Report does not meet the statutory obligation to recommend less burdensome alternatives. The commenter suggested the EPA panel members declined to make recommendations that went further than consideration or investigation of broad regulatory alternatives, with the exception of those recommendations in which the EPA rejected alternative interpretations of the CAA section 112 and relevant court cases. Two stated that the EPA did not respond to the concerns of the small business community, the SBA, or OMB, ignoring concerns expressed by the SER panelists. One commenter believes the EPA failed to convene required meetings and hearings with affected parties as required by law for small business entities. One commenter stated that the SERs' input is very important because more than 90 percent of public power utility systems meet the definition and qualify as small businesses under the SBREFA.

Response: The RFA requires that SBAR Panels collect advice and recommendations from SERs on the issues related to:

—The number and description of the small entities to which the proposed rule will apply;
—The projected reporting, recordkeeping and other compliance requirements of the proposed rule;
—Duplication, overlap or conflict between the proposed rule and other federal rules; and
—Alternatives to the proposed rule that accomplish the stated statutory objectives and minimize any significant economic impact on small entities.

The RFA does not require a covered agency to create or assemble information for SERs or for the government panel members. Although CAA section 609(b)(4) requires that the government Panel members review any material the covered agency has prepared in connection with the RFA, the law does not prescribe the materials to be reviewed. The EPA's policy, as reflected in its RFA guidance, is to provide as much information as possible, given time and resource constraints, to enable an informed Panel discussion. In this rulemaking, because of a court-ordered deadline, the EPA was unable to hold a pre-panel meeting but still provided SERs with the information available at the time, held a standard Panel Outreach meeting to collect verbal advice and recommendations from SERs, and provided the standard 14-day written comment period to SERs. The EPA received substantial input from the SERs, and the Panel report describes recommendations made by the Panel on measures the Administrator should consider that would minimize the economic impact of the proposed rule on small entities. The EPA complied with the RFA. In addition, we met with representatives of small businesses, small rural cooperatives, and small governments a number of times during the regulatory development process to discuss their issues and concerns regarding the proposed MATS rule for EGUs.

Comment: One commenter requested that the EPA work with utilities such that new regulations are as flexible and cost efficient as possible.

Response: In developing the final rule, the EPA has considered all information provided prior to, as well as in response to, the proposed rule. The EPA has endeavored to make the final regulations flexible and cost-efficient while adhering to the requirements of the CAA. The final rule includes a number of flexibilities, such as those related to monitoring requirements, that will lower costs and simplify compliance for small businesses and local governments.

Comment: One commenter was concerned about the ability of small entities or nonprofit utilities such as those owned and/or operated by rural electric co-op utilities, and municipal utilities to comply with the proposed standards within 3 years. The commenter believes that the EPA disregarded the SER panelists who explained that under these current economic conditions they have constraints on their ability to raise capital for the construction of control projects and to acquire the necessary resources in order to meet a 3-year compliance deadline. Two commenters expressed concern that smaller utilities and those in rural areas will be unable to get vendors to respond to their requests for proposals, because they will be able to make more money serving larger utilities.

Response: The preamble to the proposed rule (76 FR 25054; May 3, 2011) provides a detailed discussion of how the EPA determined compliance times for the proposed (and final) rule. The EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. *See* CAA section 112(i)(3)(B). If the situation described by commenters (*i.e.,* where small entities or nonprofit utilities constraints on ability to raise capital for construction of control projects and to acquire necessary resources) results in the source needing additional time to install controls, they would be in a position to request the 1-year extension.

Comment: Several commenters believe the EPA did not adequately consider the disproportionately large impact on smaller generating units. The commenters note the diseconomies in scale for pollution controls for such units. One commenter noted the rule will create a more serious compliance hurdle for small communities that depend on coal-fired generation to meet their base load demand. The commenter notes that by not subcategorizing units, the EPA is dictating a fuel switch due to the disproportionately high cost on small communities. The other commenter believes the MACT and NSPS standards are unachievable by going too far without really considering the impacts on small municipal units, as public power is critical to communities, jobs, economic viability and electric reliability. A generating and transmissions electric cooperative which qualifies as a small entity believes the rule will ultimately result in increased electricity costs to its members and will negatively impact the economies of the primarily rural areas that they serve. Another commenter believes there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units, particularly given the current market situation and applicable equitable factors. The commenter suggests both the EPA's and SBA's analyses focus exclusively on the effects on entities causing HAP emissions and primarily on those operating obsolete EGUs, and fail to consider either impacts on downwind businesses and governments or the positive impacts on small entities and governments owning and operating competing, clean and modern EGUs.

Response: The EPA disagrees with the commenters' belief that the impacts on smaller generating units were not adequately considered when developing the rule. The EPA determined the number of potentially impacted small entities and assessed the potential impact of the proposed action on small entities, including municipal units. A similar assessment was conducted in support of the final action. Specifically, the EPA estimated the incremental net annualized compliance cost, which is a function of the change in capital and operating costs, fuel costs, and change in revenue. The projected compliance cost was considered relative to the projected revenue from generation. Thus, the EPA's analysis accounts not only for the additional costs these entities face resulting from compliance, but also the impact of higher electricity prices. The EPA evaluated suggestions from SERs, including subcategorization recommendations. In the preamble to the proposed rule, the EPA explains that, normally, any basis for subcategorizing must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not see a distinction between emissions from smaller generating units versus larger units. The EPA acknowledges the comment that there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units.

Comment: One commenter notes that the EPA recognizes LEEs in the rule such that they should receive less onerous monitoring requirements; however, the EPA does not recognize that small and LEEs also need and merit more flexible and achievable pollution control requirements. The commenter notes that the capital costs for emissions control at small utility units is disproportionately high due to inefficiencies in Hg removal, space constraints for control technology retrofits, and the fact that small units have fewer rate base customers across which to spread these costs. The commenter cites the Michigan Department of Environmental Quality report titled ''Michigan's Mercury Electric Utility Workgroup, Final Report on Mercury Emissions from Coal-Fired Power Plants,'' (June 2005). The commenter notes that the EPA has addressed such concerns previously, citing the RIA for the 1997 8-hour ozone standard. The commenter also suggests smaller utility systems generally have less capital to invest in pollution control than larger, investor-owned systems, due to statutory inability to borrow from the private capital markets, statutory debt ceilings, limited bonding capacity, borrowing limitations related to fiscal strain posed by other, non-environmental factors, and other limitations.

Response: The EPA acknowledges that the rule contains reduced monitoring requirements for existing units that qualify as LEEs. Although the EPA does not believe that reduced pollution control requirements are warranted for LEEs, including small entity LEEs, we believe that flexible and achievable pollution control requirements are promoted through alternative standards, alternative compliance options, and emissions averaging as a means of demonstrating compliance with the standards for existing EGUs.

Comment: One commenter believes that the EPA should develop more limited monitoring requirements for small EGUs. The commenter notes small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as Hg CEMS and PM CEMS. The commenter notes the EPA could have identified monitoring alternatives to the SER panel for consideration.

Response: The EPA provided monitoring alternatives to using PM CEMS, HCl CEMS, and Hg CEMS in its proposed standards and in this final rule. The continuous compliance alternatives are available to all affected sources, including small entities. As alternatives to the use of PM CEMS and HCl CEMS, sources are allowed to conduct additional performance testing. Sorbent trap monitoring is allowed in lieu of Hg CEMS.

Comment: Several commenters believe the EPA has not sufficiently complied with the requirements of the RFA or adequately considered the impact this rulemaking would have on small entities. One commenter believes the EPA has not engaged in meaningful outreach and consultation with small entities and therefore recommends that the EPA seek to revise the court-ordered deadlines to which this rulemaking is subject, re-convene the SBAR panel, prepare a new initial regulatory flexibility analysis (IRFA), and issue it for additional public comment prior to final rulemaking. The commenter believes the IRFA does not sufficiently consider impacts on small entities as identified in the SBAR Panel Report. The commenter believes it is not apparent that the EPA considered the recommendations of the Panel. The commenter believes the description of significant alternatives in the IRFA is almost entirely quoted from the SBAR Panel Report, which the commenter does not believe is an adequate substitute for the EPA's own analysis of alternatives. The commenter also notes the EPA does not discuss the potential impacts of its decisions on small entities or the impacts of possible flexibilities. Where the EPA does consider regulatory alternatives in principle, the commenter believes it does not provide sufficient support for its decisions to understand on what basis the EPA rejected alternatives that may or may not have reduced burden on small entities while meeting the stated objectives of the rule. Additionally, the commenter notes that the EPA did not evaluate the economic or environmental impacts of significant alternatives to the proposed rule. One commenter believes that the EPA's stated reasons for declining to specify or analyze an area source standard are inadequate under the RFA. The commenter believes the EPA must give serious consideration to regulatory alternatives that accomplish the stated objectives of the CAA while minimizing any significant economic impacts on small entities and that the EPA has a duty to specify and analyze this option or to more clearly state its policy reasons for excluding serious consideration of a separate standard for area sources. A commenter believes the EPA did not fully consider the subcategorization of sources such as boilers designed to burn lignite coals versus other fossil fuels, especially in regard to non-mercury metal and acid gas emissions. The commenter references the SBAR Panel Report suggestion provided in the preamble of the proposed rule that the EPA consider developing an area source vs. major source distinction for the source category and the EPA's response. Another commenter is concerned that the recommendations made by the SER participants were ignored and not discussed in the rulemaking. Specifically, the commenter notes the EPA did not discuss subcategorizing by age, type of plant, fuel, physical space constraints or useful anticipated life of the plant. Nor did the EPA establish GACT for smaller emitters to alleviate regulatory costs and operational difficulties. A commenter believes it is likely that different numerical or work practice standards are appropriate for area sources of HAP.

Response: The EPA disagrees with one commenter's assertion that the agency has not complied with the requirements of the RFA. The EPA complied with both the letter and spirit of the RFA, notwithstanding the constraints of the court-ordered deadline. For example, the EPA notified the Chief Counsel for Advocacy of the SBA of its intent to convene a Panel; compiled a list of SERs for the Panel to consult with; and convened the Panel. The Panel met with SERs to collect their advice and recommendations; reviewed the EPA materials; and drafted a report of Panel findings. The EPA further disagrees with the commenter's assertion that the EPA's IRFA does not sufficiently consider impacts on small entities. The EPA's IRFA, which is included in chapter 10 of the RIA for the proposed rule, addresses the statutorily required elements of an IRFA, such as the economic impact of the proposed rule on small entities and the Panel's findings.

The EPA disagrees with the comment that recommendations made by the SERs were not considered or discussed in the proposed rulemaking such as recommendations regarding subcategorization and separate GACT standards for area sources. The preamble to the proposed standards includes a detailed discussion of how the EPA determined which subcategories and sources would be regulated (76 FR 25036–25037; May 3, 2011). In that discussion, the EPA explains the rationale for its proposed subcategories based on five unit design types. In addition, the EPA acknowledges the subcategorization suggestions from the SERs and explains its reasons for not subcategorizing on those bases. The preamble to the proposed standards also includes a discussion of the SERs' suggestion that area source EGUs be distinguished from major-source EGUs and the EPA's reasons for not making that distinction (76 FR 25020–25021; May 3, 2011).

The EPA also disagrees with the suggestion that the Agency pursue an extension of the timeline for final rulemaking such that the SBAR Panel can be reconvened and a new IRFA can be prepared and released for public comment prior to the final rulemaking. The EPA entered into a Consent Decree to resolve litigation alleging that the EPA failed to perform a non-discretionary duty to promulgate CAA section 112(d) standards for EGUs. *See American Nurses Ass'n* v. *EPA,* 08–2198 (D.D.C.). That Decree required the EPA to sign the final MATS rule by November 16, 2011, unless the agency sought to extend the deadline consistent with the requirements of the modification provision of the Consent Decree. The EPA and Plaintiffs stipulated to a 30-day extension consistent with the modification provisions of the Consent Decree and the rule must be signed no later than December 16, 2011. If plaintiffs in the *American Nurses* litigation objected to an additional extension request, which we believe would have been likely, the Agency would have had to file a motion with the Court seeking an extension of the deadline. Consistent with governing case law, the Agency would have been required to demonstrate in its motion for extension that it was impossible to finalize the rule by the deadline provided in the Consent Decree. *See Sierra Club* v. *Jackson,* Civil Action No. 01–1537 (D.D.C.) (Opinion of the Court denying EPA's motion to extend a consent decree deadline). The EPA negotiated a 30-day extension and was able to complete the rule by December 16, 2011; accordingly, the Agency had no basis for seeking a further extension of time.

A detailed description of the changes made to the rule since proposal, including those made as a result of feedback received during the public comment process can be found in sections VI (NESHAP) and X (NSPS) of this preamble. Changes explained in the identified sections include those related to applicability; subcategorization; work practices; periods of startup, shutdown, and malfunction; initial testing and compliance; continuous compliance; and notification, recordkeeping, and reporting.

4. Description and Estimate of the Affected Small Entities

For the purposes of assessing the impacts of MATS on small entities, a small entity is defined as:

(1) A small business according to the Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small business size standards for electric utilities is 4 billion kilowatt hours (kWh) of production or less;

(2) A small government jurisdiction that is a government of a city, county, town, district, or special district with a population of less than 50,000; and

(3) A small organization that is any not for profit enterprise that is independently owned and operated and is not dominant in its field.

The EPA examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected entities will install control technologies in compliance with MATS. This analysis does not examine potential indirect economic impacts associated with this rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

The EPA used Velocity Suite's Ventyx data as a basis for identifying plant ownership and compiling the list of potentially affected small entities. The Ventyx dataset contains detailed ownership and corporate affiliation information. The analysis focused only on those EGUs affected by the rule, which includes units burning coal, oil, petroleum coke, or coal refuse as the primary fuel, and excludes any combustion turbine units or EGUs burning natural gas. Also, because the rule does not affect combustion units with an equivalent electricity generating capacity up to 25 MW, small entities that do not own at least one combustion unit with a capacity greater than 25 MW were removed from the dataset. For the affected units remaining, boiler and generator capacity, heat input, generation, and emissions data were aggregated by owner and then by parent company. Entities with more than 4 billion kWh of annual electricity generation were removed from the list, as were municipal owned entities with a population greater than 50,000. For cooperatives, investor owned utilities, and subdivisions that generate less than 4 billion kWh of electricity annually but which may be part of a large entity, additional research on power sales, operating revenues, and other business activities was performed to make a final determination regarding size. Finally, small entities for which the IPM does not project generation in 2015 in the base case were omitted from the analysis because they are not projected to be operating and, thus, are not projected to face the costs of compliance with the rule. After omitting entities for the reasons above, the EPA identified a total of 82 potentially affected small entities that are affiliated with 102 EGUs.

5. Compliance Cost Impacts

The number of potentially affected small entities by ownership type and potential impacts of MATS are presented in Chapter 7 of the RIA and summarized here. The EPA estimated the annualized net compliance cost to small entities to be approximately $106 million in 2015 (2007$).

The EPA assessed the economic and financial impacts of the final rule using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent. Of the 82 small entities identified, The EPA's analysis shows 40 entities may experience compliance costs greater than 1 percent of base generation revenues in 2015, and 35 may experience compliance costs greater than 3 percent of base revenues. Also, all generating capacity at 3 small entities is projected to be uneconomic to maintain. In this analysis, the cost of withdrawing a unit as uneconomic is estimated as the base case profit that is forgone by not operating under the policy case. Because 35 of the 82 total units, or more than 40 percent, are estimated to incur compliance cost greater than 3 percent of base revenues, the EPA has concluded that it cannot certify that there will be no significant economic impact on a substantial number of small entities (SISNOSE) for this rule. Results for small entities discussed here do not account for the reality that electricity markets are regulated in parts of the country. Entities operating in regulated or cost-of-service markets should be able to recover all of their costs of compliance through rate adjustments.

Note that the estimated costs for small entities are significantly lower than those estimated by the EPA for the MATS proposal (which were $379 million). This is driven by a small group of units (less than 6 percent) which were projected to be uneconomic to operate under the proposal (and hence incurred lost profits due to lost electricity revenues), but are now projected to continue their operations under MATS. In addition, the EPA's modeling indicates one unit that would have operated at a low capacity factor under the base case would find it economical to increase its generation significantly under MATS to meet electricity demand in its region. Excluding this unit, the total cost impacts across all entities would be roughly $175 million. Changes in compliance behavior for this small group of units, in particular the one unit which operates at a higher capacity factor, has a substantial impact on total costs as their increased generation revenues offsets a large portion of the compliance costs.

The most significant components of incremental costs to these entities are changes in electricity revenues, followed by the increased capital and operating costs for retrofits. Capital and operating costs increase across all ownership types, but the direction of changes in electricity revenues varies among ownership types. All ownership types, with the exception of private entities, experience a net gain in electricity revenues under the MATS, unlike projections from the EPA's modeling during the proposal, where only municipals benefitted from higher electricity revenues. The change in electricity revenue takes into account both the profit lost from units that do not operate under the policy case and the difference in revenue for operating units under the policy case. According to the EPA's modeling, an estimated 274 MW of capacity owned by small entities are considered uneconomic to operate under the policy case, resulting in a net loss of $13 million (in 2007$) in profits. On the other hand, many operating units actually increase their electricity revenue due to higher electricity prices under MATS. In addition, as mentioned above, the EPA's modeling indicates one unit finds it economical to increase its capacity factor significantly under the policy case which results in significantly higher revenues offsetting the costs.

6. Description of Steps To Minimize Impacts on Small Entities

Consistent with the requirements of the RFA and SBREFA, the EPA has taken steps to minimize the significant economic impact on small entities. Because this rule does not affect units with a generating capacity of less than 25 MW, small entities that do not own at least one generating unit with a capacity greater than 25 MW are not subject to the rule. According to the EPA's analysis, among the coal- and oil-fired EGUs (*i.e.,* excluding combined cycle gas turbines and gas combustion turbines) about 26 potentially small entities only own EGUs with a capacity less than or equal to 25 MW, and none of those entities are subject to the final rule based on the statutory definition of potentially regulated units.

For units affected by the proposed rule, the EPA considered a number of comments received, both during the Small Business Advocacy Review (SBAR) Panel and the public comment period. While none of the alternatives adopted is specifically applied to small entities, the EPA believes these modifications will make compliance less onerous for all regulated units, including those owned by small entities.

a. Work practice standards. The EPA proposed numerical emission standards that would apply at all times, including during periods of startup and shutdown. After reviewing comments and other data regarding the nature of these periods of operation, the EPA is finalizing a work practice standard for periods of startup and shutdown. The EPA is also finalizing work practice standards for organic HAP from all subcategories of EGUs. Descriptions of the work practice requirements for startup and shutdown, as well as organic HAP and limited-use liquid oil-fired EGUs, can be found in section VI.D–E. of the preamble.

b. Continuous compliance and notification, record-keeping, and reporting. The final rule greatly simplifies the continuous compliance requirements and provides two basic approaches for most situations: use of continuous monitoring and periodic testing. The frequency of periodic testing has been decreased from monthly in the proposal to quarterly in the final rule. In addition to simplifying compliance, the EPA believes these changes considerably reduce the overall burden associated with recordkeeping and reporting. These changes to the final rule are described in more detail in Section VI.G–H of this preamble.

c. Subcategorization. The Small Entity Representatives on the SBAR Panel were generally supportive of subcategorization and suggested a number of additional subcategories the EPA should consider when developing the final rule. Although it was not consistent with the statute to adopt the proposed subcategories, the EPA maintained the existing subcategories and split the ''liquid oil-fired units'' subcategory into three subcategories—continental, non-continental units, and limited-use units.

d. MACT floor calculations. As recommended by the EPA SBAR Panel representative, the EPA established the MACT floors using all the available ICR data that was received to the maximum extent possible consistent with the CAA requirements. The Agency believes this approach reasonably ensures that the emission limits selected as the MACT floors adequately represent the level of emissions actually achieved by the average of the units in the top 12 percent, considering operational variability of those units.

e. Alternatives not adopted. The EPA did not adopt several of the suggestions posed either during the SBAR Panel or public comment period. The EPA did not propose a percent reduction standard as an alternative to the concentration-based MACT floor. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's consideration of coal preparation practices that remove Hg and other HAP before firing. Also, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s), and such an approach would be difficult to implement and enforce. Furthermore, the EPA does not believe the percent reduction standard is in line with the Court's interpretation of the CAA section 112 requirements. Even if we believed it was appropriate to establish a percent reduction standard, we do not have the data necessary to establish percent reduction standards for HAP, as explained further in the response to comments document.

The EPA determined not to establish GACT standards for area sources for a number of reasons. The data show that similar HAP emissions and control technologies are found on both major and area sources greater than 25 MW, and some large units are synthetic area sources. In fact, because of the significant number of well-controlled EGUs of all sizes, we believe it would be difficult to make a distinction between MACT and GACT. Moreover, the EPA believes the standards for area source EGUs should reflect MACT, rather than GACT, because there is no essential difference between area source and major source EGUs with respect to emissions of HAP.

The EPA determined not to exercise its discretionary authority to establish health-based emission standards for HCl and other HAP acid gases. Given the limitations of the currently available information (*e.g.,* the HAP mix where EGUs are located, and the cumulative impacts of respiratory irritants from nearby sources), the environmental effects of HCl and the other acid gas HAP, and the significant co-benefits from reductions in criteria pollutants the EPA determined that setting a conventional MACT standard for HCl and the other acid gas HAP was the appropriate course of action.

As required by SBREFA section 212, the EPA also is preparing a Small Entity Compliance Guide to help small entities comply with this rule. Small entities will be able to obtain a copy of the Small Entity Compliance guide at the following Web site: *http://www.epa.gov/airquality/powerplanttoxics/actions.html.*

D. Unfunded Mandates Reform Act of 1995

Title II of the UMRA of 1995, Public Law 104–4, 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, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, UMRA section 205 generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of UMRA section 205 do not apply when they are inconsistent with applicable law. Moreover, UMRA section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under UMRA section 203. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this rule contains 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 1 year. Accordingly, we have prepared a written statement entitled ''Unfunded Mandates Reform Act Analysis'' under

UMRA section 202 that is within the RIA and which is summarized below.

1. Statutory Authority

As discussed elsewhere in this preamble, the statutory authority for this rulemaking is CAA section 112. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. CAA section 112(b) lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

CAA section 112(d) directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT-based standards. This NESHAP applies to all coal- and oil-fired EGUs.

In compliance with UMRA section 205(a), we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives were presented in the RIA for the rulemaking.

The regulatory alternative upon which this rule is based represents the MACT floor for all regulated pollutants for all but one EGU subcategory for all but one regulated pollutant for that subcategory. These MACT floor-based standards represent the least costly and least burdensome alternative. Beyond-the-floor emission limits for Hg are for existing coal-fired EGUs in the subcategory for low rank virgin coal EGUs.

2. Social Costs and Benefits

The RIA prepared for this rule including the Agency's assessment of costs and benefits is in the docket.

It is estimated that HAP would be reduced by thousands of tons in 2015, relative to the base case, including reductions in HCl, HF, metallic HAP (including Hg), and several other organic HAP from EGUs. Studies have determined a relationship between exposure to certain of these HAP and the onset of cancer; however, the Agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, significant reductions in $PM_{2.5}$ and SO_2 will occur, including approximately 53 thousand tons of $PM_{2.5}$ and over 1 million tons of SO_2. These reductions will occur by 2016 and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days (*i.e.,* days when employees are unable to work). Although we are unable to monetize the benefits associated with the HAP emissions reductions other than for Hg or all benefits associated with Hg reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2016 associated with the implementation of the final rule range from $37 billion to $90 billion (2007 dollars) when using a 3 percent discount rate or from $33 billion to $81 billion (2007 dollars) when using a 7 percent discount rate). Our estimate of costs is $9.6 billion (2007 dollars). For more detailed information on the benefits and costs estimated for this rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of this rule are discussed previously in this preamble.

The EPA assessed the economic and financial impacts of the rule on government-owned entities using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent of base revenues. The EPA projects that 42 government entities will have compliance costs greater than 1 percent of base generation revenue in 2016, and 32 may experience compliance costs greater than 3 percent of base revenues. Overall, 6 units owned by government entities are expected to retire. The most significant components of incremental costs to these entities are the increased capital and operating costs, followed by changes in electricity revenues. For more details on these results and the methodology behind their estimation, see the results included in chapter 7 of the RIA.

4. Effects on the National Economy

The UMRA requires that we estimate the effect of this rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this rule is presented in the RIA in the docket. This analysis provides estimates of the effect of this rule on some of the categories mentioned above.

The results of the economic impact analysis are summarized previously in this preamble. The results show that, relative to baseline, there will be an average 3.1 percent increase in electricity price on average nationwide in 2016, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S., and a less than 1 percent increase in natural gas price nationwide in 2016. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[377] Power generation from coal-fired plants will fall by about 2 percent nationwide in 2016. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a result of this rule. To put the electricity price effects in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[378] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[379] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[380]

5. Consultation With Government

The UMRA requires that we describe the extent of the Agency's prior consultation with affected state, local,

[377] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[378] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 t0 2010, Table 8–10.

[379] Ibid.

[380] Ibid., EIA AEO 2010, Table–10 for price levels; and Chapterr 3 of the RIA for electricity price differential.

and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, UMRA section 203 requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a regulatory action. Consistent with the intergovernmental consultation provisions of UMRA section 204, the EPA initiated consultations with governmental entities affected by this rule. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on October 27, 2010, 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 of 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 rule, answer questions, and solicit input from state/local governments. During the meeting, officials asked clarifying questions regarding CAA section 112 requirements and central decision points presented by the EPA (*e.g.,* use of surrogate pollutants to address HAP, subcategorization of source category, assessment of emissions variability). They also expressed uncertainty with regard to how utility boilers owned/operated by state and local entities would be impacted, as well as with regard to the potential burden associated with implementing the rule on state and local entities (*i.e.,* burden to re-permit affected EGUs or update existing permits). Officials requested, and the EPA provided, addresses associated with the 112 state and local governments estimated to be potentially impacted by the rule. The EPA has not received additional questions or requests from state or local officials.

Consistent with UMRA section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Because the potential existed for a significant impact for substantial number of small entities, the EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of the rule. As part of that process, the EPA considered several options, which are discussed previously in this preamble. Those options included establishing emission limits, establishing work practice standards, establishing subcategories, and consideration of monitoring options. The regulatory alternative selected is a combination of the options considered and includes provisions regarding a number of the recommendations resulting from the SBAR Panel process as described below (see the Regulatory Flexibility Act discussion in this section of the preamble for more detail).

E. Executive Order 13132, Federalism

Under EO 13132, the EPA may not issue an action that has federalism 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 state and local governments, or the EPA consults with state and local officials early in the process of developing the final action.

The EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. Accordingly, the EPA provides the following federalism summary impact statement as required by section 6(b) of EO 13132.

Based on estimates in the RIA, provided in the docket, the final rule may have federalism implications because the rule may impose approximately $294 million in annual direct compliance costs on an estimated 96 state or local governments. Specifically, we estimate that there are 80 municipalities, 5 states, and 11 political subdivisions (*i.e.,* a public district with territorial boundaries embracing an area wider than a single municipality and frequently covering more than one county for the purpose of generating, transmitting and distributing electric energy) that may be directly impacted by this final rule. Responses to the EPA's 2010 ICR were used to estimate the nationwide number of potentially impacted state or local governments. As previously explained, this 2010 survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of DOE/EIA's ''Annual Electric Generator Report,'' and ''Power Plant Operations Report.''

The EPA consulted with state and local officials in the process of developing the rule to permit them to have meaningful and timely input into its development. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the rule, answer questions, and solicit input. In the final rule, EPA has provided flexibilities that will lower compliance costs for these entities. The EPA also recognizes that municipalities may need a longer compliance timeframe because of required approval processes.

F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

Subject to 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. Executive Order 13175 requires the 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.''

The EPA has concluded that this action may have tribal implications. The EPA offered consultation with tribal officials early in the regulation development process to permit them an opportunity to have meaningful and timely input. Consultation letters were sent to 584 tribal leaders and provided information regarding the EPA's development of this rule and offered consultation. At the request of the tribes, three consultation meetings were held: December 7, 2010, with the Upper Sioux Community of Minnesota; December 13, 2010, with Moapa Band of Paiutes, Forest County Potawatomi, Standing Rock Sioux Tribal Council, and Fond du Lac Band of Chippewa; January 5, 2011, with the Forest County Potawatomi, and a representative from the National Tribal Air Association (NTAA). In these meetings, the EPA presented the authority under the CAA used to develop these rules and an overview of the industry and the industrial processes that have the potential for regulation. Tribes expressed concerns about the impact of EGUs in Indian country. Specifically, they were concerned about potential Hg deposition and the impact on the water resources of the tribes, with particular concern about the impact on subsistence lifestyles for fishing communities, the cultural impact of impaired water quality for ceremonial purposes, and the economic impact on tourism. In light of these concerns, the tribes expressed interest in an expedited implementation of the rule. Other concerns expressed by tribes related to how the Agency would consider variability in setting the standards, and the use of tribal-specific fish consumption data from the tribes in our assessments. They were not supportive of using work practice standards as part of the rule, and asked the Agency to consider going beyond the MACT floor to offer more protection for the tribal communities.

In addition to these consultations, the EPA also conducted outreach on this rule through presentations at the National Tribal Forum in Milwaukee, WI; phone calls with the NTAA; and a webinar for tribes on the proposed rule. The EPA specifically requested tribal data that could support the appropriate and necessary analyses and the RIA for this rule. In addition, the EPA held individual consultations with the Navajo Nation on October 12, 2011; as well as the Gila River Indian Community, Ak-Chin Indian Community, and the Hopi Nation on October 14, 2011. These tribes expressed concerns about the impact of the rule on the Navajo Generating Station (NGS), the impact on the cost of the water allotted to the tribes from the Central Arizona Project (CAP), the impact on tribal revenues from the coal mining operations (*i.e.,* assumptions about reduced mining if NGS were to retire one or more units), and the impacts on employment of tribal members at both the NGS and the mine. More specific comments can be found in the docket.

The EPA will continue to work with these and other potentially affected tribes as this final rule is implemented.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

This final rule is subject to EO 13045 (62 FR 19885; April 23, 1997) because it is an economically significant regulatory action as defined by EO 12866, and EPA believes that the environmental health or safety risk addressed by this action may have a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of the standards on children.

Although this final rule is based on technology performance, the standards are designed to protect against hazards to public health with an adequate margin of safety as described in Section III of this preamble. The protection offered by this rule is particularly important for children, especially the developing fetus. As referenced in Chapter 4 of the RIA, ''Mercury and Other HAP Benefits Analysis,'' children are more vulnerable than adults to many HAP emitted by EGUs due to differential behavior patterns and physiology. These unique susceptibilities were carefully considered in a number of different ways in the analyses associated with this rulemaking, and are summarized in the RIA. We also estimate substantial health improvements for children in the form of 130,000 fewer asthma attacks, 3,100 fewer emergency room visits due to asthma, 6,300 fewer cases of acute bronchitis, and approximately 140,000 fewer cases of upper and lower respiratory illness.

H. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355; May 22, 2001) requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, OMB, for actions identified as ''significant energy actions.'' This action, which is a significant regulatory action under EO 12866, is likely to have a significant adverse effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action as follows.

We estimate a 3.1 percent price increase for electricity nationwide in 2016 and a less than 2 percent percentage fall in coal-fired power production as a result of this rule. The EPA projects that electric power sector-delivered natural gas prices will increase by about 0.6 percent over the 2015 to 2030 timeframe. For more information on the estimated energy effects, please refer to the economic impact analysis for this final rule. The analysis is available in the RIA, which is in the public docket.

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; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in its regulatory 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) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. The EPA cites the following standards in the final rule: EPA Methods 1, 2, 2A, 2C, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 23, 26, 26A, 29, 30B of 40 CFR part 60 and Method 320 of 40 CFR part 63. Consistent with the NTTAA, the EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results have been documented and are placed in the docket for the proposed rule.

The three voluntary consensus standards described below were identified as acceptable alternatives to EPA test methods for the purposes of the final rule.

The voluntary consensus standard American National Standards Institute (ANSI)/American Society of Mechanical Engineers (ASME) PTC 19–10–1981, ''Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus]'' is cited in the final rule for its manual method for measuring the O_2, CO_2, and CO content of exhaust gas. This part of ANSI/ASME PTC 19–10–1981 is an acceptable alternative to Method 3B.

The voluntary consensus standard ASTM D6348–03 (Reapproved 2010), ''Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy'' is acceptable as an alternative to Method 320 and is cited in the final rule, but with several conditions: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; and (2) In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be 70% $\geq$ R $\leq$ 130%. If the %R value does not meet this criterion for a target compound, the test data are not acceptable for that compound and the test must be repeated for that analyte (*i.e.,* the sampling and/or analytical procedure should be adjusted before a retest). The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound by using the following equation: *Reported Result = (Measured Concentration in the Stack* $\times$ *100)/% R.*

The voluntary consensus standard ASTM D6784–02, ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method),'' is an acceptable alternative to use of EPA Method 29 for Hg only or Method 30B for the purpose of conducting relative accuracy tests of Hg continuous monitoring systems under this final rule. Because of the limitations of this method in terms of total sampling volume, it is not appropriate for use in performance testing under this rule. In addition to the voluntary consensus standards the EPA used in the final rule, the search for emissions measurement procedures identified 16 other voluntary consensus standards. The EPA determined that 14 of these 16 standards identified for measuring emissions of the HAP or other pollutants subject to emission standards in the final rule were impractical alternatives to EPA test methods for the purposes of this final rule. Therefore, the EPA did not adopt these standards for this purpose. The reasons for this determination for the 14 methods are discussed below, and the remaining 2 methods are discussed later in this section.

The voluntary consensus standard ASTM D3154–00, ''Standard Method for Average Velocity in a Duct (Pitot Tube Method),'' is impractical as an alternative to EPA Methods 1, 2, 3B, and 4 for the purposes of this rulemaking because the standard appears to lack in quality control and quality assurance requirements. Specifically, ASTM D3154–00 does not include the following: (1) proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (*e.g.,* magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The voluntary consensus standard ASTM D3464–96 (Reapproved 2001), ''Standard Test Method Average Velocity in a Duct Using a Thermal Anemometer,'' is impractical as an alternative to EPA Method 2 for the purposes of this rule primarily because applicability specifications are not clearly defined, *e.g.,* range of gas composition, temperature limits. Also, the lack of supporting quality assurance data for the calibration procedures and specifications, and certain variability issues that are not adequately addressed by the standard limit the EPA's ability to make a definitive comparison of the method in these areas.

The voluntary consensus standard ISO 10780:1994, ''Stationary Source Emissions—Measurement of Velocity and Volume Flowrate of Gas Streams in Ducts,'' is impractical as an alternative to EPA Method 2 in this rule. The standard recommends the use of an L-shaped pitot, which historically has not been recommended by the EPA. The EPA specifies the S-type design which has large openings that are less likely to plug up with dust.

The voluntary consensus standard, CAN/CSA Z223.2–M86 (1999), ''Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides of Nitrogen in Enclosed Combustion Flue Gas Streams,'' is unacceptable as a substitute for EPA Method 3A because it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided are non-mandatory and also do not provide the same level of quality assurance as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods require drift checks after each run.

Two very similar voluntary consensus standards, ASTM D5835–95 (Reapproved 2001), ''Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration,'' and ISO 10396:1993, ''Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations,'' are impractical alternatives to EPA Method 3A for the purposes of this final rule because they lack in detail and quality assurance/quality control requirements. Specifically, these two standards do not include the following: (1) Sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only).

The voluntary consensus standard ISO 12039:2001, ''Stationary Source Emissions—Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen—Automated Methods,'' is not acceptable as an alternative to EPA Method 3A. This ISO standard is similar to EPA Method 3A, but is missing some key features. In terms of sampling, the hardware required by ISO 12039:2001 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039:2001 only specifies a two-point calibration while EPA Method 3A specifies a three-point calibration. Also, ISO 12039:2001 does not specify performance criteria for calibration error, calibration drift, or sampling system bias tests as in the EPA method, although checks of these quality control features are required by the ISO standard.

The voluntary consensus standard ASTM D6522–00, ''Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers'' is not an acceptable alternative to EPA Method 3A for measuring CO and O_2 concentrations for this final rule as the method is designed for application to sources firing natural gas.

The voluntary consensus standard ASME PTC–38–80 R85 (1985), ''Determination of the Concentration of Particulate Matter in Gas Streams,'' is not acceptable as an alternative for EPA Method 5 because ASTM PTC–38–80 is not specific about equipment requirements, and instead presents the options available and the pros and cons of each option. The key specific differences between ASME PTC–38–80 and the EPA methods are that the ASME standard: (1) Allows in-stack filter placement as compared to the out-of-stack filter placement in EPA Methods 5 and 17; (2) allows many different types of nozzles, pitots, and filtering equipment; (3) does not specify a filter weighing protocol or a minimum allowable filter weight fluctuation as in the EPA methods; and (4) allows filter paper to be only 99 percent efficient, as compared to the 99.95 percent efficiency required by the EPA methods.

The voluntary consensus standard ASTM D3685/D3685M–98, ''Test Methods for Sampling and Determination of Particulate Matter in Stack Gases,'' is similar to EPA Methods 5 and 17, but is lacking in the following areas that are needed to produce quality, representative particulate data: (1) Requirement that the filter holder temperature should be between 120°C and 134°C, and not just ''above the acid dew-point''; (2) detailed specifications for measuring and monitoring the filter holder temperature during sampling; (3) procedures similar to EPA Methods 1, 2, 3, and 4, that are required by EPA Method 5; (4) technical guidance for performing the Method 5 sampling procedures, *e.g.,* maintaining and monitoring sampling train operating temperatures, specific leak check guidelines and procedures, and use of reagent blanks for determining and subtracting background contamination; and (5) detailed equipment and/or operational requirements, *e.g.,* component exchange leak checks, use of glass cyclones for heavy particulate loading and/or water droplets, operating under a negative stack pressure, exchanging particulate loaded filters, sampling preparation and implementation guidance, sample recovery guidance, data reduction guidance, and particulate sample calculations input.

The voluntary consensus standard ISO 9096:1992, ''Determination of Concentration and Mass Flow Rate of Particulate Matter in Gas Carrying Ducts—Manual Gravimetric Method,'' is not acceptable as an alternative for EPA Method 5. Although sections of ISO 9096 incorporate EPA Methods 1, 2, and 5 to some degree, this ISO standard is not equivalent to EPA Method 5 for collection of PM. The standard ISO 9096 does not provide applicable technical guidance for performing many of the integral procedures specified in Methods 1, 2, and 5. Major performance and operational details are lacking or nonexistent, and detailed quality assurance/quality control guidance for the sampling operations required to produce quality, representative particulate data (*e.g.,* guidance for maintaining and monitoring train operating temperatures, specific leak check guidelines and procedures, and sample preparation and recovery procedures) are not provided by the standard, as in EPA Method 5. Also, details of equipment and/or operational requirements, such as those specified in EPA Method 5, are not included in the ISO standard, *e.g.,* stack gas moisture measurements, data reduction guidance, and particulate sample calculations.

The voluntary consensus standard CAN/CSA Z223.1–M1977, ''Method for the Determination of Particulate Mass Flows in Enclosed Gas Streams,'' is not acceptable as an alternative for EPA Method 5. Detailed technical procedures and quality control measures that are required in EPA Methods 1, 2, 3, and 4 are not included in CAN/CSA Z223.1. Second, CAN/CSA Z223.1 does not include the EPA Method 5 filter weighing requirement to repeat weighing every 6 hours until a constant weight is achieved. Third, EPA Method 5 requires the filter weight to be reported to the nearest 0.1 milligram (mg), while CAN/CSA Z223.1 requires reporting only to the nearest 0.5 mg. Also, CAN/CSA Z223.1 allows the use of a standard pitot for velocity measurement when plugging of the tube opening is not expected to be a problem. The EPA Method 5 requires an S-shaped pitot.

The voluntary consensus standard EN 1911–1,2,3 (1998), ''Stationary Source Emissions-Manual Method of Determination of HCl-Part 1: Sampling of Gases Ratified European Text-Part 2: Gaseous Compounds Absorption Ratified European Text-Part 3: Adsorption Solutions Analysis and Calculation Ratified European Text,'' is impractical as an alternative to EPA Methods 26 and 26A. Part 3 of this standard cannot be considered equivalent to EPA Method 26 or 26A because the sample absorbing solution (water) would be expected to capture both HCl and chlorine gas, if present, without the ability to distinguish between the two. The EPA Methods 26 and 26A use an acidified absorbing solution to first separate HCl and chlorine gas so that they can be selectively absorbed, analyzed, and reported separately. In addition, in EN 1911 the absorption efficiency for chlorine gas would be expected to vary as the pH of the water changed during sampling.

The voluntary consensus standard EN 13211 (1998), is not acceptable as an alternative to the Hg portion of EPA Method 29 primarily because it is not validated for use with impingers, as in the EPA method, although the method describes procedures for the use of impingers. This European standard is validated for the use of fritted bubblers only and requires the use of a side (split) stream arrangement for isokinetic sampling because of the low sampling rate of the bubblers (up to 3 liters per minute, maximum). Also, only two bubblers (or impingers) are required by EN 13211, whereas EPA Method 29 require the use of six impingers. In addition, EN 13211 does not include many of the quality control procedures of EPA Method 29, especially for the use and calibration of temperature sensors and controllers, sampling train assembly and disassembly, and filter weighing.

Two of the 16 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, ''Flow Measurement by Velocity Traverse,'' for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, ''Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters,'' for EPA Method 2.

Finally, in addition to the three voluntary consensus standards identified as acceptable alternatives to EPA methods required in the final rule, the EPA is also specifying four voluntary consensus standards in the rule for use in sampling and analysis of liquid oil samples for moisture content. These standards are: ASTM D95–05 (Reapproved 2010), ''Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation,'' ASTM D4006–11, ''Standard Test Method for Water in Crude Oil by Distillation,'' ASTM D4177–95 (Reapproved 2010), ''Standard Practice for Automatic Sampling of Petroleum and Petroleum Products,'' and ASTM D4057–06 (Reapproved 2011), ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products.''

Table 5, section 4.1.1.5 of appendix A, and section 3.1.2 of appendix B to subpart UUUUU, 40 CFR part 63, list the EPA testing methods included in the final rule. Under section 63.7(f) and section 63.8(f) of subpart A of the General Provisions, a source may apply to the EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures specified.

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 (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ 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 final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, and indigenous populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low income, and indigenous populations.

This final rule establishes national emission standards for new and existing EGUs that combust coal and oil. The EPA estimates that there are approximately 1,400 units located at 600 facilities covered by this final rule.

This final rule will reduce emissions of all the listed HAP that come from EGUs. This includes metals (Hg, As, Be, Cd, Cr, Pb, Mn, Ni, and Se), organics (POM, acetaldehyde, acrolein, benzene, dioxins, ethylene dichloride, formaldehyde, and PCB), and acid gases (HCl and HF). At sufficient levels of exposure, these pollutants can cause a range of health effects including cancer; irritation of the lungs, skin, and mucous membranes; effects on the central nervous system such as memory and IQ loss and learning disabilities; damage to the kidneys; and other acute health disorders.

The final rule will also result in substantial reductions of criteria pollutants such as CO, PM, and SO_2. Sulfur dioxide is a precursor pollutant that is often transformed into fine PM ($PM_{2.5}$) in the atmosphere. Reducing direct emissions of $PM_{2.5}$ and SO_2 will, as a result, reduce concentrations of $PM_{2.5}$ in the atmosphere. These reductions in $PM_{2.5}$ will provide large health benefits, such as reducing the risk of premature mortality for adults, chronic and acute bronchitis, childhood asthma attacks, and hospitalizations for other respiratory and cardiovascular diseases. (For more details on the health effects of metals, organics, and $PM_{2.5}$, please refer to the RIA contained in the docket for this rulemaking.) This final rule will also have a small effect on electricity and natural gas prices but has the potential to affect the cost structure of the utility industry and could lead to shifts in how and where electricity is generated.

This final rule is one of a group of regulatory actions that the EPA has taken and will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to HAP and $PM_{2.5}$, as well as to other pollutants, from EGUs and other sources. In addition, the EPA will pursue energy efficiency improvements throughout the economy, along with other federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements. Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from EJ communities, among many others.

1. Key EJ Aspects of the Rule

This is an air toxics rule; therefore, it does not permit emissions trading among sources. Instead, this final rule will place a limit on the rates of Hg and other HAP emitted from each affected EGU. As a result, emissions of Hg and other HAP such as HCl will be substantially reduced in the vast majority of states. In some states, however, there may be small increases in Hg and other HAP emissions due to shifts in electricity generation from EGUs with higher emission rates to EGUs with already low emission rates. Hydrogen chloride emissions are projected to increase at a small number of sources but that does not lead to any increased emissions at the state level.

The primary risk analysis to support the finding that this final rule is both appropriate and necessary includes an analysis of the effects of Hg from EGUs on people who rely on freshwater fish they catch as a regular and frequent part of their diet. These groups are characterized as subsistence level fishing populations or fishers. A significant portion of the data in this analysis came from published studies of EJ communities where people frequently consume locally-caught freshwater fish. These communities included: (1) White and black populations (including female and poor strata) surveyed in South Carolina; (2) Hispanic, Vietnamese and Laotian populations surveyed in California; and (3) Great Lakes tribal populations (Chippewa and Ojibwe) active on ceded territories around the Great Lakes. These data were used to help estimate risks to similar populations beyond the areas where the study data were collected. For example, while the Vietnamese and Laotian survey data were collected in California, given the ethnic (heritage) nature of these high fish consumption rates, we assumed that they could also be associated with members of these ethnic groups living elsewhere in the U.S. Therefore, the high-end consumption rates referenced in the California study for these ethnic groups were used to model risk at watersheds elsewhere in the U.S. As a result of this approach, the specific fish consumption patterns of several different EJ groups are fundamental to the EPA's assessment of both the underlying risks that make this final rule appropriate and necessary, and of the analysis of the benefits of reducing exposure to Hg and the other HAP.

The EPA's full analysis of risks from consumption of Hg-contaminated fish is contained in the RIA for this rule. The effects of this final rule on the health risks from Hg and other HAP are presented in the preamble and in the RIA for this rule.

2. Potential Environmental and Public Health Impacts to Minority, Low Income, or Tribal Populations

The EPA has conducted several analyses that provide additional insight on the potential effects of this rule on EJ communities. These include: (1) The socio-economic distribution of people living close to affected EGUs who may be exposed to pollution from these sources; and (2) an analysis of the distribution of health effects expected from the reductions in $PM_{2.5}$ that will result from implementation of this final rule (co-benefits).

a. Socio-Economic Distribution. As part of the analysis for this final rule, the EPA reviewed the aggregate demographic makeup of the communities near EGUs covered by this final rule. Although this analysis gives some indication of populations that may be exposed to levels of pollution that cause concern, it does not identify the demographic characteristics of the most highly affected individuals or communities. Electric generating units usually have very tall emission stacks; this tends to disperse the pollutants emitted from these stacks fairly far from the source. In addition, several of the pollutants emitted by these sources, such as a common form of Hg and SO_2, are known to travel long distances and contribute to adverse impacts on both the environment and human health hundreds or even thousands of miles from where they were emitted (in the case of elemental Hg, globally).

The proximity-to-the-source review is included in the analysis for this final rule because some EGUs emit enough HAP such as Ni or Cr(VI) to cause elevated lifetime cancer risks greater than 1 in a million in nearby communities. In addition, the EPA's analysis indicates that there are localized areas with potential for elevated levels of Hg deposition around most U.S. EGUs.[381]

The analysis of demographic data used proximity-to-the-source as a surrogate for exposure to identify those populations considered to be living near affected sources, such that they have notable exposures to current HAP

[381] See Excess Local Deposition TSD for more detail.

emissions from these sources. The demographic data for this analysis were extracted from the 2000 census data which were provided to the EPA by the U.S. Census Bureau. Distributions by race are based on demographic information at the census block level, and all other demographic groups are based on the extrapolation of census block group level data to the census block level. The socio-demographic parameters used in the analysis included the following categories: Racial (White, African American, Native American, Other or Multiracial, and All Other Races); Ethnicity (Hispanic); and Other (Number of people below the poverty line, Number of people with ages between 0 and 18, Number of people greater than or equal to 65, Number of people with no high school diploma).

In determining the aggregate demographic makeup of the communities near affected sources, the EPA focused on those census blocks within three miles of affected sources and determined the demographic composition (*e.g.,* race, income, etc.) of these census blocks and compared them to the corresponding compositions nationally. The radius of 3 miles (or approximately 5 kilometers) is consistent with other demographic analyses focused on areas around potential sources. In addition, air quality modeling experience has shown that the area within three miles of an individual source of emissions can generally be considered the area with the highest ambient air levels of the primary pollutants being emitted for most sources, both in absolute terms and relative to the contribution of other sources (assuming there are other sources in the area, as is typical in urban areas). Although facility processes and fugitive emissions may have more localized impacts, the EPA acknowledges that because of various stack heights there is the potential for dispersion beyond 3 miles. To the extent that any minority, low income, and indigenous subpopulation is disproportionately impacted by the current emissions as a result of the proximity of their homes to these sources, that subpopulation also stands to see increased environmental and health benefit from the emissions reductions called for by this rule. The results of the EPA's demographic analysis for affected sources are shown in the following table: [382] [383]

TABLE 12—COMPARATIVE SUMMARY OF THE DEMOGRAPHICS WITHIN 5 KM (3 MILES) OF THE AFFECTED SOURCES

[Population in millions] [382]

	White	African American	Native American	Other and multi-racial	Hispanic	Minority [383]	Below poverty line
Near Source Total (3 mi)	8.78	2.51	0.10	2.52	2.86	5.13	2.43
% of Near Source Total	63	18	1	18	21	37	17
National Total	215	35	2.49	33.3	39.1	70.8	37.1
% of National Total	75	12	1	12	14	25	13

[382] Racial and ethnic categories overlap and cannot be summed.
[383] The ''Minority'' population is the overall population (in the first row) minus white population (in the second row).

The data indicate that coal-fired EGUs are located in areas where the minority share of the population living within a three mile buffer is higher than the national average by 12 percentage points or 48 percent. For these same areas, the percent of the population below the poverty line is also higher than the national average by 4 percentage points or 31 percent. These results are presented in more detail in the ''Review of Proximity Analysis,'' February 2011, a copy of which is available in the docket.

b. $PM_{2.5}$ (Co-Benefits) Analysis. As mentioned above, many of the steps EGUs will take to reduce their emissions of air toxics as required by this final rule will also reduce emissions of PM and SO_2. As a result, this final rule will reduce concentrations of $PM_{2.5}$ in the atmosphere. Exposure to $PM_{2.5}$ can cause or contribute to adverse health effects, such as asthma and heart disease, that significantly affect many minority, low-income, and tribal individuals and their communities. Fine PM ($PM_{2.5}$) is particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure can cause premature death and trigger heart attacks, asthma attacks in children and adults with asthma, chronic and acute bronchitis, and emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. Missing work due to illness or the illness of a child is a particular problem for people who have jobs that do not provide paid sick days. Low-wage employees also risk losing their jobs if they are absent too often, even if it is due to their own illness or the illness of a child or other relative. Finally, many individuals in these communities lack access to high quality health care to treat these types of illnesses. Due to all these factors, many minority and low-income communities are particularly susceptible to the health effects of $PM_{2.5}$ and receive a variety of benefits from reducing it.

We estimate that in 2016 the annual PM-related benefits of the final rule for adults include approximately 4,200 to 11,000 fewer premature mortalities, 2,900 fewer cases of chronic bronchitis, 4,800 fewer non-fatal heart attacks, 2,600 fewer hospitalizations (for respiratory and cardiovascular disease combined), 3.2 million fewer days of restricted activity due to respiratory illness and approximately 540,000 fewer lost work days. As described in EO 13045, Protection of Children from Environmental Health Risks and Safety Risks, we also estimate substantial health improvements for children.

We also examined the $PM_{2.5}$ mortality risks according to race, income, and educational attainment. We then estimated the change in $PM_{2.5}$ mortality risk as a result of this final rule among people living in the counties with the highest (top 5 percent) $PM_{2.5}$ mortality risk in 2005. We then compared the change in risk among the people living in these ''high-risk'' counties with people living in all other counties.

In 2005, people living in the highest risk counties and in the poorest counties had a substantially higher risk of $PM_{2.5}$-related death than people living in the other 95 percent of counties. This was true regardless of race; the difference between the groups of counties for each race was large while the differences among races in both groups of counties was very small. In contrast, the analysis found that people with less than high school education had a significantly greater risk from $PM_{2.5}$ mortality than people with a greater than high school education. This was true both for the highest-risk counties and for the other counties. In summary, the analysis indicates that in 2005, educational status, living in one of the poorest counties, and living in a high-risk county are associated with higher $PM_{2.5}$ mortality risk while race is not.

Our analysis demonstrates that this final rule will significantly reduce the $PM_{2.5}$ mortality among all populations of different races living throughout the U.S. compared to both 2005 and 2016 pre-rule (*i.e.,* base case) levels. The analysis indicates that people living in counties with the highest rates (top 5 percent) of $PM_{2.5}$ mortality risk in 2005 receive the largest reduction in mortality risk after this rule takes effect. We also find that people living in the poorest 5 percent of the counties receive a larger reduction in $PM_{2.5}$ mortality risk than all other counties. More information can be found in Section 7.11 of the RIA.

The EPA estimates that the benefits of the final rule are distributed among races, income levels, and levels of education fairly evenly. However, the analysis does indicate that this final rule in conjunction with the implementation of existing or final rules (*e.g.,* the CSAPR) will reduce the disparity in risk between those in the highest-risk counties and the other 95 percent of counties for all races and educational levels. In addition, in many cases implementation of this final rule and other rules will, together, reduce risks in the highest-risk counties to the approximate level of risk for the rest of the counties as it existed before implementation of the rule.

These results are presented in more detail in Section 7.11 of the RIA.

3. Meaningful Public Participation

The EPA defines ''environmental justice'' to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. To promote meaningful involvement, the EPA publicized the rulemaking via newsletters, EJ listserves, and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/RuleGate.nsf/*). During the comment period, the EPA discussed the proposed rule via a conference call with communities, conducted a community-oriented webinar on the proposed rule, and posted the webinar presentation on-line. The EPA also held three public hearings to receive additional input on the proposal.

There will continue to be opportunities for public notice and comment as the utilities move forward with implementation of this rule. Once the rule is finalized, affected EGUs will need to update their Title V operating permits to reflect their new emission limits, any other new applicable requirements, and the associated monitoring and recordkeeping from this rule. The Title V permitting process provides that when most permits are reopened (for example, to incorporate new applicable requirements) or renewed, there must be opportunity for public review and comments. In addition, after the public review process, the EPA has an opportunity to review the proposed permit and object to its issuance if it does not meet CAA requirements.

4. Additional Analysis

In addition to the previously described assessment of EJ impacts, the EPA conducted an analysis of sub-populations with particularly high potential risks of Hg exposure due to high rates of fish consumption. These populations overlap in many cases with traditional EJ populations and would benefit from Hg reductions resulting from this rule. The EPA also conducted an analysis of the distribution of $PM_{2.5}$-related mortality risk according to the race, income and education of the population and how MATS changes this distribution. These analyses can be found in Section 7.12 of the RIA.

5. Summary

This final rule strictly limits the emissions rate of Hg and other HAP from every affected EGU. The EPA's analysis indicates substantial health benefits, including for minority, low income, and indigenous populations, from reductions in $PM_{2.5}$.

The EPA's analysis also indicates reductions in risks for individuals, including for members of minority populations, who eat fish frequently from U.S. lakes and rivers and who live near affected sources. Based on all the available information, the EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, and indigenous populations. The EPA is providing multiple opportunities for EJ communities to both learn about and comment on this rule and welcomes their participation as implementation of the rule proceeds.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act 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**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective April 16, 2012.

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: December 16, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of the Federal Regulations is 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.*

Subpart A—[Amended]

■ 2. Section 60.17 is amended:

■ a. By redesignating paragraph (a)(93), added March 21, 2011, at 76 FR 15750, and delayed indefinitely at 76 FR 28664, May 18, 2011, as paragraph (a)(96);

■ b. By redesignating paragraphs (a)(91) and (a)(92) as paragraphs (a)(94) and (a)(95);
■ c. By redesignating paragraphs (a)(89) and (a)(90) as paragraphs (a)(91) and (a)(92);
■ d. By redesignating paragraphs (a)(54) through (a)(88) as paragraphs (a)(55) through (a)(89);
■ e. By adding paragraph (a)(54);
■ f. By adding paragraph (a)(90); and
■ g. By adding paragraph (a)(93) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(54) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, approved September 1, 2008, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(90) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, approved July 15, 2011, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(93) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, approved August 1, 2010, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

Subpart B—[Amended]

■ 3. Section 60.21 is amended as follows:
■ a. By revising paragraph (a).
■ b. By revising paragraph (f).
■ c. By removing paragraph (k).

§ 60.21 Definitions.

* * * * *

(a) *Designated pollutant* means any air pollutant, the 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 that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

* * * * *

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

* * * * *

■ 4. Section 60.24 is amended as follows:
■ a. By revising paragraph (b)(1).
■ b. By removing paragraph (h).

§ 60.24 Emission standards and compliance schedules.

* * * * *

(b) * * *

(1) Emission standards shall either be based on an allowance system or 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.

* * * * *

Subpart D—[Amended]

■ 5. The subpart heading for Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

■ 6. Section 60.40 is amended by revising paragraph (e) to read as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.

■ 7. Section 60.41 is amended by adding the definition of ''natural gas'' in alphabetical order to read as follows:

§ 60.41 Definitions.

* * * * *

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.

* * * * *

■ 8. Section 60.42 is amended as follows:
■ a. By revising paragraph (a) introductory text.
■ b. By adding paragraph (d).
■ c. By adding paragraph (e).

§ 60.42 Standard for particulate matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, 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 that:

* * * * *

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM is exempt from the PM standards specified in paragraph (a) of this section.

■ 9. Section 60.45 is amended as follows:
■ a. By revising paragraph (a).
■ b. By revising paragraph (b) introductory text.
■ c. By revising paragraphs (b)(1) through (5).
■ d. By revising paragraph (b)(6) introductory text.
■ e. By revising paragraphs (b)(7)(i)(A) through (C).
■ f. By revising paragraph (b)(7)(ii)(B).
■ g. By adding paragraph (b)(8).

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO_2 emissions, NO_X emissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS 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 combusts only gaseous or liquid fossil fuel (excluding residual oil)

with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO_2 emissions are not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2 emissions is not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for NO_X 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 NO_X are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NO_X emissions is not required. If the initial performance test results show that NO_X emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_X 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 is not required to and elects not to install any CEMS for either SO_2 or NO_X, a CEMS for measuring either O_2 or CO_2 is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

* * * * *

(7) * * *

(i) * * *

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(ii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

* * * * *

Subpart Da—[Amended]

■ 10. The subpart heading for Subpart Da is revised to read as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

■ 11. Section 60.40Da is amended by revising paragraphs (b)(1) and (e) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

* * * * *

(b) * * *

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) in the combustion turbine engine and associated heat recovery steam generator; and

* * * * *

(e) Applicability of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) through (3) of this section.

(1) Affected facilities (*i.e.* heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (*i.e.* heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators use with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (*i.e.* duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part.)

(3) Any affected facility that meets the applicability requirements and is subject to subpart Eb or subpart CCCC of this part is not subject to the emission standards under subpart Da.

■ 12. Section 60.41Da is amended as follows:

■ a. By revising the definitions of ''boiler operating day'', ''gaseous fuel'', ''integrated gasification combined cycle electric utility steam generating unit'', ''natural gas'', ''petroleum'', ''potential combustion concentration'', and ''steam generating unit''.

■ b. By adding the definitions of ''affirmative defense'', ''combined heat and power'', ''gross energy output'', ''net energy output'', ''out-of-control period'', and ''petroleum coke'' in alphabetical order.

■ c. By removing the definitions of ''available purchase power'', ''cogeneration'', ''dry flue gas desulfurization technology '', ''electric utility company'', ''emergency condition'', ''emission rate period'', ''gross output'', ''interconnected'', ''net system capacity'', ''principal company'', ''responsible official'', ''spare flue gas desulfurization system module'', ''spinning reserve'', ''system emergency reserves'', and ''system load''.

§ 60.41Da Definitions.

* * * * *

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.

* * * * *

Boiler operating day for units constructed, reconstructed, or modified before February 29, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

* * * * *

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.

* * * * *

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 energy output means:

(1) For facilities constructed, reconstructed, or modified before May 4, 2011, the gross electrical or mechanical output from the affected facility 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);

(2) For facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) 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);

(3) For combined heat and power facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility divided by 0.95 minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) 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);

(4) For a IGCC electric utility generating unit that coproduces chemicals constructed, reconstructed, or modified after May 3, 2011, the gross useful work performed is the gross electrical or mechanical output from the unit minus electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) that are associated with power production 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). Auxiliary loads that are associated with power production are determined based on the energy in the coproduced chemicals compared to the energy of the syngas combusted in combustion turbine engine and associated duct burners.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam 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.

* * * * *

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 energy output means the gross energy output minus the parasitic load associated with power production. Parasitic load includes, but is not limited to, the power required to operate the equipment used for fuel delivery systems, air pollution control systems, wastewater treatment systems, ash handling and disposal systems, and other controls (*i.e.,* pumps, fans, compressors, motors, instrumentation, and other ancillary equipment required to operate the affected facility).

* * * * *

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.

Petroleum for facilities constructed, reconstructed, or modified before May 4, 2011, means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil. For units constructed, reconstructed, or modified after May 3, 2011, *petroleum* means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Petroleum coke, also known as ''petcoke,'' means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy residues). *Petroleum* *coke* is typically derived from oil refinery coker units or other cracking processes.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems. For sulfur dioxide (SO_2) the potential combustion concentration is determined under § 60.50Da(c).

* * * * *

Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, 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). For units constructed, reconstructed, or modified after May 3, 2011, *steam 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 combustion turbines and fuel cells.

* * * * *

■ 13. Section 60.42Da is revised to read as follows:

§ 60.42Da Standards for particulate matter (PM).

(a) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

(b) Except as provided in paragraphs (b)(1) and (b)(2) of this section, on and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(1) An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart is exempt from the opacity standard specified in this paragraph (b) of this section.

(2) An owner or operator of an affected facility that combusts only natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

(c) Except as provided in paragraphs (d) and (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of:

(1) 13 ng/J (0.030 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) For an affected facility that commenced construction or reconstruction, 0.1 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) when combusting solid, liquid, or gaseous fuel, or

(3) For an affected facility that commenced modification, 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.8 percent reduction) when combusting solid, liquid, or gaseous fuel.

(e) Except as provided in paragraph (f) of this section, the owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall meet the requirements specified in paragraphs (e)(1) and (2) of this section.

(1) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator shall cause to be discharged into the atmosphere from that affected facility at all times except during periods of startup and shutdown, any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction, any gases that contain PM in excess of either:

(A) 11 ng/J (0.090 lb/MWh) gross energy output; or

(B) 12 ng/J (0.097 lb/MWh) net energy output.

(ii) For an affected facility which commenced modification, any gases that contain PM in excess of 13 ng/J (0.015 lb/MMBtu) heat input.

(2) During periods of startup and shutdown, the owner or operator shall meet the work practice standards specified in Table 3 to subpart UUUUU of part 63.

(f) An owner or operator of an affected facility that meets the conditions in either paragraphs (f)(1) or (2) of this section is exempt from the PM emissions limits in this section.

(1) The affected facility combusts only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and that does not use a post-combustion technology to reduce emissions of SO_2 or PM.

(2) The affected facility is operated under a PM commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da.

■ 14. Section 60.43Da is amended as follows:

■ a. The section heading is revised.

■ b. By revising paragraphs (a)(1) and (2).

■ c. By adding paragraphs (a)(3) and (4).

■ d. By removing and reserving paragraph (c).

■ e. By revising paragraph (f).

■ f. By revising paragraph (i).

■ g. By revising paragraph (k).

■ h. By adding paragraph (l).

■ i. By adding paragraph (m).

§ 60.43Da Standards for sulfur dioxide (SO_2).

(a) * * *

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction);

(2) 30 percent of the potential combustion concentration (70 percent

reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input;

(3) 180 ng/J (1.4 lb/MWh) gross energy output; or

(4) 65 ng/J (0.15 lb/MMBtu) heat input.

* * * * *

(f) The SO_2 standards under this section do not apply to an owner or operator of an affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

* * * * *

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

* * * * *

(k) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

(l) Except as provided in paragraphs (j) and (m) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (l)(1) and (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO_2 in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 140 ng/J (1.2 lb/MWh) net energy output; or

(iii) 3 percent of the potential combustion concentration (97 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(m) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (m)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

■ 15. Section 60.44Da is revised to read as follows:

§ 60.44Da Standards for nitrogen oxides (NO_X).

(a) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before July 10, 1997 any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit in paragraphs (a)(1) and (2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emissions limit listed in the following table as applicable to the fuel type combusted and as determined on a 30-boiler operating day rolling average basis.

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	([1])	([1])
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace [2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit [2]	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1] Exempt from NO_X standards and NO_X monitoring requirements.
[2] Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) When two or more fuels are combusted simultaneously in an affected facility, the applicable emissions limit (E_n) is determined by proration using the following formula:

$$En = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

En = Applicable NO_X emissions limit when multiple fuels are combusted simultaneously (ng/J heat input);
w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;
x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;
y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;
z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and
v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(b) [Reserved]

(c) [Reserved]

(d) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after July 9, 1997, but before March 1, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (d)(1) and (2) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 200 ng/J (1.6 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of 65 ng/J (0.15 lb/MMBtu) heat input.

(e) Except as provided in paragraphs (f) and (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (e)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(f) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005 but before May 4, 2011, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

(3) In cases when during a 30-boiler operating day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the

30-day compliance period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

(g) Except as provided in paragraphs (h) of this section and § 60.45Da, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_X in excess of either:

(i) 88 ng/J (0.70 lb/MWh) gross energy output; or

(ii) 95 ng/J (0.76 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_X in excess of either:

(i) 110 ng/J (0.85 lb/MWh) gross energy output; or

(ii) 120 ng/J (0.92 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of 140 ng/J (1.1 lb/MWh) gross energy output.

(h) The NO_X emissions limits under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

■ 16. Section 60.45Da is revised to read as follows:

§ 60.45Da Alternative standards for combined nitrogen oxides (NO_X) and carbon monoxide (CO).

(a) The owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011 as alternate to meeting the applicable NO_X emissions limits specified in § 60.44Da may elect to meet the applicable standards for combined NO_X and CO specified in paragraph (b) of this section.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) plus CO in excess of the applicable emissions limit specified in paragraphs (b)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_X plus CO in excess of either:

(i) 140 ng/J (1.1 lb/MWh) gross energy output; or

(ii) 150 ng/J (1.2 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_X plus CO in excess of either:

(i) 160 ng/J (1.3 lb/MWh) gross energy output; or

(ii) 170 ng/J (1.4 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_X plus CO in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

■ 17. Section 60.47Da is amended as follows:

■ a. By revising paragraph (c).
■ b. By adding paragraph (f).
■ c. By adding paragraph (g).
■ d. By adding paragraph (h).
■ e. By adding paragraph (i).

§ 60.47Da Commercial demonstration permit.

* * * * *

(c) An owner or operator of an affected facility that uses fluidized bed combustion (atmospheric or pressurized) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43Da(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

* * * * *

(f) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the total PM emission reduction requirements under § 60.42Da but must, as a minimum, reduce PM emissions to less than 6.4 ng/J (0.015 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 standards or emission reduction requirements under § 60.43Da but must, as a minimum, reduce SO_2 emissions to 5 percent of the potential combustion concentration (95 percent reduction) or to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(h) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions control system or advanced combustion controls who is issued a commercial demonstration permit by the Administrator is not subject to the NO_X standards or emission reduction requirements under § 60.44Da but must, as a minimum, reduce NO_X emissions to less than 130 ng/J (1.0 lb/MWh) or the combined NO_X plus CO emissions to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(i) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category listed in the following table.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	SO_2	1,000

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	NO_X	1,000
Multi-pollutant Emission Control	PM	1,000
Pressurized Fluidized Bed Combustion	SO_2	1,000
Pressurized Fluidized Bed Combustion	NO_X	1,000
Pressurized Fluidized Bed Combustion	PM	1,000
Advanced Combustion Controls	NO_X	1,000

■ 18. Section 60.48Da is amended as follows:

■ a. By revising paragraphs (a) through (g).

■ b. By revising paragraph (i).

■ c. By revising paragraph (k)(1)(i).

■ d. By revising paragraph (k)(2)(i).

■ e. By revising paragraph (k)(2)(iv).

■ f. By removing and reserving paragraph (l).

■ g. By revising paragraph (m).

■ h. By revising paragraph (n).

■ i. By revising paragraphs (p)(5), (7), and (8).

■ j. By adding paragraph (r).

■ k. By adding paragraph (s).

§ 60.48Da Compliance provisions.

(a) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, the applicable PM emissions limit and opacity standard under § 60.42Da, SO_2 emissions limit under § 60.43Da, and NO_X emissions limit under § 60.44Da apply at all times except during periods of startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, the applicable SO_2 emissions limit under § 60.43Da, NO_X emissions limit under § 60.44Da, and NO_X plus CO emissions limit under § 60.45Da apply at all times. The applicable PM emissions limit and opacity standard under § 60.42Da apply at all times except during periods of startup and shutdown.

(b) After the initial performance test required under § 60.8, compliance with the applicable SO_2 emissions limit and percentage reduction requirements under § 60.43Da, NO_X emissions limit under § 60.44Da, and NO_X plus CO emissions limit under § 60.45Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for both SO_2, NO_X or NO_X plus CO as applicable, and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards.

(c) For the initial performance test required under § 60.8, compliance with the applicable SO_2 emissions limits and percentage reduction requirements under § 60.43Da, the NO_X emissions limits under § 60.44Da, and the NO_X plus CO emissions limits under § 60.45Da is based on the average emission rates for SO_2, NO_X, CO, and percent reduction for SO_2 for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(d) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits is determined by dividing the sum of the SO_2 and NO_X emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

(e) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable SO_2 percentage reduction requirements is determined based on the ''as fired'' total potential emissions and the total outlet SO_2 emissions for the 30 successive boiler operating days.

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable daily average PM emissions limits is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable daily average PM emissions limits is determined by dividing the sum of the PM emissions for the 30 successive boiler operating days by the sum of the gross useful output or net energy output, as applicable, for the 30 successive boiler operating days.

(g) For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average NO_X plus CO emissions limit is determined by dividing the sum of the NO_X plus CO emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

* * * * *

(i) Compliance provisions for sources subject to § 60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), (f), or (g). The owner or operator shall calculate NO_X emissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_X output concentration in ppm (measured according to the provisions of § 60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, NO_X emissions may be calculated by multiplying the hourly NO_X emission rate in lb/MMBtu (measured by the CEMS required under § 60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(k) * * *

(1) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 2 in this section:

$$\mathbf{E} = \frac{(Csg \times Qsg) - (Cte \times Qte)}{(Osg \times \mathbf{h})} \qquad \textbf{(Eq. 2)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

C_{te} = Average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h);

Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/h (dscf/h);

O_{sg} = Average hourly gross energy output from steam generating unit, J/h (MW); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

* * * * *

(2) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 3 in this section:

$$\mathbf{E} = \frac{(Csg \times Qsg)}{Occ} \qquad \textbf{(Eq. 3)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in § 60.49Da(l), determine the mass rate (lb/h) of NO_X emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_X shall be computed using Equation 4 in this section:

$$\mathbf{E} = \frac{(\mathbf{ER}sg \times Hcc)}{Occ} \qquad \textbf{(Eq. 4)}$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

ER_{sg} = Average hourly emission rate of NO_X exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H_{cc} = Average hourly heat input rate of entire combined cycle unit, J/h (MMBtu/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(m) Compliance provisions for sources subject to § 60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), (j)(3)(i), (l)(1)(i), (l)(1)(ii), or (l)(2). The owner or operator shall calculate SO_2 emissions as 1.660×10^{-7} lb/scf-ppm times the average hourly SO_2 output concentration in ppm (measured according to the provisions of § 60.49Da(b)), times the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, SO_2 emissions may be calculated by multiplying the hourly SO_2 emission rate (in lb/MMBtu), measured by the CEMS required under § 60.49Da, by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(n) Compliance provisions for sources subject to § 60.42Da(c)(1) or (e)(1)(i). The owner or operator shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of § 60.49Da(t)), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

* * * * *

(p) * * *

(5) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-boiler operating day rolling average basis. Beginning on January 1, 2012, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

* * * * *

(7) All non-out-of-control CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, non-out-of-control emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-boiler operating day rolling average.

* * * * *

(r) Compliance provisions for sources subject to § 60.45Da. To determine compliance with the NO_X plus CO emissions limit, the owner or operator shall use the procedures specified in paragraphs (r)(1) through (3) of this section.

(1) Calculate NO_X emissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_X output concentration in ppm (measured according to the provisions of § 60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(2) Calculate CO emissions by multiplying the average hourly CO output concentration (measured according to the provisions of § 60.49Da(u), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(3) Calculate NO_X plus CO emissions by summing the NO_X emissions results from paragraph (r)(1) of this section plus the CO emissions results from paragraph (r)(2) of this section.

(s) Affirmative defense for exceedance of emissions limit during malfunction. In response to an action to enforce the standards set forth in paragraph §§ 60.42Da, 60.43Da, 60.44Da, and 60.45Da, 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 you fail to meet your burden of proving all of the requirements in the affirmative defense as specified in paragraphs (s)(1) and (2) of this section. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (s)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) 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; and

(B) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emissions limits were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount, and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) 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; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) 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.

(2) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, 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 in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (s)(1) 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 exceedance.

■ 19. Section 60.49Da is amended as follows:

■ a. By revising paragraphs (a)(1) and (2).

■ b. By revising paragraph (a)(3) introductory text.
■ c. By revising paragraph (a)(3)(ii).
■ d. By revising paragraph (a)(3)(iii)(B).
■ e. By adding paragraph (a)(4).
■ f. By revising paragraph (b) introductory text.
■ g. By revising paragraph (b)(2).
■ h. By revising paragraph (e).
■ i. By revising paragraph (k) introductory text.
■ j. By revising paragraph (k)(3).
■ k. By revising paragraph (l).
■ l. By removing and reserving paragraph (p).
■ m. By removing and reserving paragraph (q).
■ n. By removing and reserving paragraph (r).
■ o. By revising paragraph (t).
■ p. By revising paragraph (u)(1)(iii).
■ q. By revising paragraph (v)(4).

§ 60.49Da Emission monitoring.

(a) * * *

(1) Except as provided for in paragraphs (a)(2) and (4) of this section, the owner or operator of an affected facility subject to an opacity standard, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2 control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), or (iv) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in § 60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs § 60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO_2 or PM;

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO_2, or CO emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section; or

(iv) The affected facility uses an ESP and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part.

(3) The owner or operator of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to using a COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section. The opacity performance test requirement in paragraph (a)(3)(i) must be conducted by April 29, 2011, within 45 days after stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later.

* * * * *

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a)(3)(i) of this section according to the applicable schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(C) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(C) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(iii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(4) An owner or operator of an affected facility that is subject to an opacity standard under § 60.42a(b) is not required to operate a COMS provided that affected facility meets the conditions in either paragraph (a)(4)(i) or (ii) of this section.

(i) The affected facility combusts only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.51a(d).

(ii) The owner or operator of the affected facility installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where natural gas and/or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/

MMBtu) or less are the only fuels combusted, as follows:

* * * * *

(2) For a facility that qualifies under the numerical limit provisions of § 60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere.

* * * * *

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross energy output for sources demonstrating compliance with an output-based standard.

* * * * *

(3) For an affected facility generating process steam in combination with electrical generation, the gross energy output is determined according to the definition of ''gross energy output'' specified in § 60.41Da that is applicable to the affected facility.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emissions limit in § 60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) * * *

(1) * * *

(iii) At a minimum, non-out-of-control 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-boiler operating day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(v) * * *

(4) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFire database.

* * * * *

■ 20. Section 60.50Da is amended as follows:

■ a. By revising paragraph (b).

■ b. By removing paragraph (g).

■ c. By removing paragraph (h).

■ d. By removing paragraph (i).

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(b) In conducting the performance tests to determine compliance with the PM emissions limits in § 60.42Da, the owner or operator shall meet the requirements specified in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator shall measure filterable PM to determine compliance with the applicable PM emissions limit in § 60.42Da as specified in paragraphs (b)(1)(i) through (ii) of this section.

(i) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(ii) For the PM concentration, Method 5 of appendix A of this part shall be used for an affected facility that does not use a wet FGD. For an affected facility that uses a wet FGD, Method 5B of appendix A of this part shall be used downstream of the wet FGD.

(A) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ± 14 °C (320 ± 25 °F).

(B) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2 traverse points. 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.

(2) In conjunction with a performance test performed according to the requirements in paragraph (b)(1) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall measure condensable PM using Method 202 of appendix M of part 51.

(3) Method 9 of appendix A of this part and the procedures in § 60.11 shall be used to determine opacity.

* * * * *

■ 21. Section 60.51Da is amended as follows:

■ a. By revising paragraph (a).

■ b. By revising paragraph (b)(5).

■ c. By revising paragraph (d).

■ d. By removing and reserving paragraph (g).

■ e. By revising paragraph (k).

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and NO_X plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) must be reported to the Administrator.

(b) * * *

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

* * * * *

(d) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) and conducting performance tests using Method 9 of appendix A–4 of this part shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraph (d)(1) of this section.

(1) For each performance test conducted using Method 9 of appendix

A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets.

(2) [Reserved]

* * * * *

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (b) and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.

§ 60.52Da [Amended]

■ 22. Section 60.52Da is amended by removing and reserving paragraph (a).

Subpart Db—[Amended]

■ 23. Section 60.40b is amended as follows:

■ a. By revising paragraph (c).

■ b. By revising paragraph (h).

■ c. By revising paragraph (i).

■ d. By adding paragraph (1).

■ e. By adding paragraph (m).

§ 60.40b Applicability and delegation of authority.

* * * * *

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

* * * * *

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.,* heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_X standards under this subpart and the PM standards under subpart BB.

(m) Temporary boilers are not subject to this subpart.

24. Section 60.41b is amended by revising the definition of ''distillate oil'', and adding the definition of ''temporary boiler'' in alphabetical order to read as follows:

§ 60.41b Definitions.

* * * * *

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), kerosine, 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).

* * * * *

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

■ 25. Section 60.43b is amended by revising paragraph (f) to read as follows:

§ 60.43b Standard for particulate matter (PM).

* * * * *

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

* * * * *

■ 26. Section 60.44b is amended as follows:

■ a. The section heading is revised.

■ b. By revising paragraph (b) introductory text.

■ c. By revising paragraph (c).

■ d. By revising paragraph (d).

■ e. By revising paragraph (e).

■ f. By revising paragraph (l)(1).

§ 60.44b Standard for nitrogen oxides (NO_X).

* * * * *

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

* * * * *

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

* * * * *

(l) * * *

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

* * * * *

■ 27. Section 60.46b is amended by revising paragraph (j)(14) to read as follows:

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(j) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

■ 28. Section 60.48b is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraphs (a)(1)(i) through (iii) .

■ c. By revising paragraph (a)(2)(ii).

■ d. By revising paragraph (j) introductory text.

■ e. By revising paragraph (j)(5).

■ f. By revising paragraph (j)(6).

■ g. By adding paragraph (j)(7).

■ h. By adding paragraph (l).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

* * * * *

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

* * * * *

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.49b(h).

■ 29. Section 60.49b is amended by revising paragraph (r)(1) to read as follows.

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(r) * * *

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

* * * * *

Subpart Dc—[Amended]

■ 30. Section 60.40c is amended as follows:

■ a. By revising paragraph (a).
■ b. By revising paragraph (e).
■ c. By revising paragraph (f).
■ d. By revising paragraph (g).
■ e. By adding paragraph (h).
■ f. By adding paragraph (i).

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

* * * * *

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

■ 31. Section 60.41c is amended as follows:

■ a. By removing the definition of ''Cogeneration.''
■ b. By revising the definition of ''Distillate oil.''
■ c. By adding a definition of ''Temporary boiler'' in alphabetical order.

§ 60.41c Definitions.

* * * * *

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, 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).

* * * * *

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

■ 32. Section 60.42c is amended as follows:

■ a. By revising paragraph (c)(1) and (3).

■ b. By revising paragraph (d).

■ c. By revising paragraph (e)(1)(ii).

■ d. By revising paragraph (h) introductory text.

■ e. By revising paragraph (h)(3).

■ f. By adding paragraph (h)(4).

§ 60.42c Standard for sulfur dioxide (SO_2).

* * * * *

(c) * * *

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

* * * * *

(3) Affected facilities located in a noncontinental area; or

* * * * *

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) * * *

(1) * * *

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

* * * * *

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

* * * * *

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

* * * * *

■ 33. Section 60.43c is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraph (b) introductory text.

■ c. By revising paragraph (c).

■ d. By revising paragraphs (e)(1), (3), and (4).

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

* * * * *

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

* * * * *

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

* * * * *

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

* * * * *

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur

or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

■ 34. Section 60.45c is amended as follows:
■ a. By revising paragraph (c)(14).
■ b. By revising paragraph (d).

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

* * * * *

(c) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

■ 35. Section 60.47c is amended as follows:
■ a. By revising paragraph (a) introductory text.
■ b. By revising paragraphs (a)(1)(i) through (iii).
■ c. By revising paragraph (a)(2)(ii).
■ d. By revising paragraph (f).
■ e. By removing paragraph (g).

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

Subpart HHHH—[Removed and Reserved]

■ 36. Subpart HHHH is removed and reserved.

PART 63—[AMENDED]

■ 37. The authority citation for 40 CFR Part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[Amended]

■ 38. Section 63.14 is amended as follows:
■ a. By adding paragraphs (b)(19) and (20).
■ b. By adding paragraphs (b)(22) and (23).
■ c. By adding paragraphs (b)(69) through (72).
■ d. By revising paragraph (i)(1).

§ 63.14 Incorporation by reference.

* * * * *

(b) * * *

(19) ASTM D95–05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(i).

(20) ASTM Method D388–05, Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for § 63.10042.

* * * * *

(22) ASTM Method D396–10, Standard Specification for Fuel Oils, including Appendix X1, approved October 1, 2010, IBR approved for § 63.10042.

(23) ASTM D4006–11, Standard Test Method for Water in Crude Oil by Distillation, including Annex A1 and Appendix X1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(ii).

* * * * *

(69) ASTM D4057–06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, including Annex A1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(iv).

(70) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, including Annexes A1 through A6 and Appendices X1 and X2, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(iii).

(71) ASTM D6348–03 (Reapproved 2010), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, approved October 1, 2010, IBR approved for table 1 to subpart UUUUU of this part, table 2 to subpart UUUUU of this part, table 5 to subpart UUUUU of this part, and appendix B to subpart UUUUU of this part.

(72) ASTM D6784–02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 5 to subpart UUUUU of this part, and appendix A to subpart UUUUU of this part.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus],'' IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, table 4 to subpart JJJJJJ of this part, and table 5 to subpart UUUUU of this part.

* * * * *

■ 39. Part 63 is amended by adding subpart UUUUU to read as follows:

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in § 63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in § 63.10042 of this subpart.

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, and existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in 63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in 63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011, and you meet the applicability criteria at the time you commence construction.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after May 3, 2011, and you meet the applicability criteria at the time you commence reconstruction.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change process (*e.g.,* fuel or utilization) is considered to be an existing source under this subpart.

§ 63.9983 Are any EGUs not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit, covered by 40 CFR part 63, subpart YYYY.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and combusts natural gas for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but did not fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

§ 63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in § 63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.

(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under § 63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in § 63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.

§ 63.9985 What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.

(2) An EGU that commenced reconstruction or modification after May 3, 2011.

(b) [Reserved]

Emission Limitations and Work Practice Standards

§ 63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in § 63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and

(2) EGUs designed for low rank virgin coal.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in § 63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

§ 63.9991 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under § 63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

(b) As provided in § 63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO_2 limit in Tables 1 and 2 to this subpart only if your coal-fired EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and SO_2 continuous emissions monitoring system (CEMS) installed on the unit; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology installed on the unit consistent with § 63.10000(b).

General Compliance Requirements

§ 63.10000 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct the initial performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits, with two exceptions:

(A) You may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration, and

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-fired fuel fired EGU or IGCC EGU is new.

(ii) For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status.

(iii) For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(iv) If your coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or compliance performance testing repeated quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total non-mercury HAP metals, individual non-mercury HAP metals or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) You may also opt to install and operate a particulate matter CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively, in accordance with § 63.10010(i).

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO_2) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO_2 emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For an existing liquid oil-fired unit, you may conduct the performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a LEE for one or more pollutants. For a qualifying LEE for Hg emissions limits, you must conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. For a qualifying LEE of any other applicable emissions limits, you must conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status.

(ii) If your existing liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or performance testing conducted quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total HAP metals, individual HAP metals, or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test at least annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) If you elect to use a PM CEMS, you will use the CEMS in accordance with § 63.10010(i) to demonstrate initial and continuous compliance with the filterable PM emission limit.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance by conducting periodic quarterly performance stack tests for HCl and HF. If you elect to demonstrate compliance through quarterly performance testing, then you must also develop a site-specific monitoring plan to ensure that the operations of the unit remain consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in § 63.10042, then you are not subject to the emission limits in Tables 1 and 2, but must comply with the performance tune-up work practice requirements in Table 3.

(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to part 60 or part 75 of this chapter, and that meet the requirements of § 63.10010. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.

(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of § 63.10010 (*e.g.,* if the CMS was previously certified under another program).

(4) You must operate and maintain the CMS according to the site-specific monitoring plan.

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CEMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device). See § 63.10010(a) for further details. For CPMS installations, follow the procedures in § 63.10010(h).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations), including ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§ 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with § 63.8(c)(7)(i) and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§ 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to § 63.10021(e).

(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (*e.g.*, 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.*, 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) If you no longer meet the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that you last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h)(1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i)(1) If you own or operate an EGU subject to this subpart, and it has been at least 6 months since you operated in a manner that caused you to meet the definition of an EGU subject to this subpart, you may, consistent with paragraph (g) of this section, select the date on which your EGU will no longer be subject to this subpart. You must be in compliance with any newly applicable section 112 or 129 standards on the date you selected.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§ 63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

§ 63.10001 Affirmative defense for exceedence of emission limit during malfunction.

In response to an action to enforce the standards set forth in § 63.9991 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 63.2. Appropriate penalties may be assessed, however, if you fail to meet your 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, you 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, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem 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; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(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; and

(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; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source 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) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, 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 in § 63.9991 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 exceedance.

Testing and Initial Compliance Requirements

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the applicable date in paragraph (f) of this section for tune-up work practices for existing EGUs, in § 63.9984 for other requirements for existing EGUs, and in paragraph (g) of this section for all requirements for new EGUs.

(1) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to this subpart using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If you are required to establish operating limits (see paragraph (d) of this section and Table 4 to this subpart), you must collect all applicable parametric data during the performance test period. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.*, an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test consists of 30 boiler operating days of data collected by the initial compliance demonstration date specified in § 63.10005 with the certified monitoring system.

(i) The 30-boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to this subpart.

(ii) If you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the performance test period.

(b) *Performance testing requirements.* If you choose to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to this subpart for your EGUs, you must conduct the tests according to § 63.10007 and Table 5 to this subpart. For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in § 63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in § 63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid data CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in § 63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(c) *Operating limits.* In accordance with § 63.10010 and Table 4 to this subpart, you may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of your initial compliance demonstration.

(d) *CMS requirements.* If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO_2, HCl, or HF emissions limit in Table 1 or 2 of this subpart through use of an SO_2, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 of this subpart through use of a PM CEMS installed, certified, and operated in accordance with § 63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see § 63.10007(e)), meets the applicable SO_2, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19–19 of Method 19 in appendix A–7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (Note: for this calculation, the term E_{hj} in Equation 19–19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(2) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to this subpart using initial performance testing and continuous monitoring with PM CPMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply.

(iii) You must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this

subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984 for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) *Tune-ups.* All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to § 63.10021(e).

(f) For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in § 63.9984 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may not pursue this compliance option if your existing EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration.

(1) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if you collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in § 63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in § 63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30-boiler operating day performance test using Method 30B in appendix A–8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A–1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. You may use a pair of sorbent traps to sample the stack gas for no more than 10 days.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A–3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A–1 and A–2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A–1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from § 75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly electrical load data (megawatts), from facility records.

(ii) If you use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in µg/m^3 (dry basis), for the 30-boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and electrical load for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in § 63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A–3 and A–4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values "C_h", "Q_h", "B_{ws}" and "$(MW)_h$" with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(*1*) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^6 to convert it to TBtu/hr; or

(*2*) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^3 to convert it to GW; or

(*3*) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95–05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation," or

(ii) ASTM D4006–11, "Standard Test Method for Water in Crude Oil by Distillation," including Annex A1 and Appendix A1, or

(iii) ASTM D4177–95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products," including Annexes A1 through A6 and Appendices X1 and X2, or

(iv) ASTM D4057–06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products," including Annex A1.

(5) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in § 63.10030.

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

(a) For liquid oil-fired, solid oil-derived fuel- and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under § 63.10000(c), you must conduct all applicable performance tests according to Table 5 to this subpart and § 63.10007 at least every year.

(b) For affected units meeting the LEE requirements of § 63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and § 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1).

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, you must conduct Hg emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1). You must have 3 calendar years of testing and CEMS or

sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emission limit, for liquid oil-fired EGUs, you must conduct all applicable periodic emissions tests for filterable PM, or individual or total HAP metals emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in § 63.10000(c)(2)(iii).

(f) Unless you follow the requirements listed in paragraphs (g) and (h) of this section, performance tests required at least every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test; performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test; and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in § 63.10021(d)(1).

(g) If you elect to demonstrate compliance using emissions averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10021(e).

(1) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 36 calendar months after the previous performance tune-up.

(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 48 calendar months after the previous performance tune-up.

(j) You must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in § 63.10031.

§ 63.10007 What methods and other procedures must I use for the performance tests?

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to § 63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(1) If you use CEMS (Hg, HCl, SO_2, or other) to determine compliance with a 30-boiler operating day rolling average emission limit, you must collect data for all nonexempt unit operating conditions (see § 63.10011(g) and Table 3 to this subpart).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (*e.g.,* quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(3) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose to comply with the filterable PM emission limit and demonstrate continuous performance using a PM CPMS for an applicable emission limit as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b)(5) and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (*e.g.,* laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (*e.g.,* analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in

sections 12.2 and 12.3 of EPA Method 19 in appendix A–7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO_2 ppm by 1.66×10^{-7};

(ii) Multiply HCl ppm by 9.43×10^{-8};

(iii) Multiply HF ppm by 5.18×10^{-8};

(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24×10^{-8}; and

(v) Multiply Hg concentrations (µg/scm) by 6.24×10^{-11}.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A–2 or A–3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A–2 or A–3, replacing the value of K with 1.66×10^{-7} lb/scf-ppm for SO_2, 9.43×10^{-8} lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-8} lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining C_h as the average SO_2, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§ 63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A–4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10^3 term from Equation A–4 to determine the pollutant emission rate in lb/MWh.

(f) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

§ 63.10008 [Reserved]

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) *General eligibility.* (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of § 63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the ‘‘unit designed for coal ≥ 8,300 Btu/lb’’ subcategory are equal to or less than 1.0 lb/TBtu or 1.1E–2 lb/GWh or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2, according to the procedures in this section. Note that except for Hg emissions from EGUs in the ‘‘unit designed for coal ≥ 8,300 Btu/lb’’ subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance testing. The averaging time for emissions averaging for Hg from EGUs in the ‘‘unit designed for coal ≥ 8,300 Btu/lb’’ subcategory is 90 days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance testing. For the purposes of this paragraph, 30- (or 90-day) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group has operated 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross electrical output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) *Equations.* Use the following equations when performing calculations for your EGU emissions averaging group:

(1) *Group eligibility equations.*

$$WAERm = \frac{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Herm_i \times Rmm_i)\right]_p\right] + \sum_{i=1}^{m}(Ter_i \times Rmt_i)}{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n} Rmm_i\right]_p\right] + \sum_{i=1}^{m} Rmt_i} \quad (Eq. 1a)$$

Where:

WAERm = Weighted average emissions rate maximum in terms of lb/heat input or lb/gross electrical output,

$Herm_i$ = Hourly emissions rate (*e.g.,* lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring for hour i,

Rmm_i = Maximum rated heat input or gross electrical output of unit i in terms of heat input or gross electrical output,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent test of unit i in terms of lb/heat input or lb/gross electrical output,

Rmt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAERm = \frac{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Herm_i \times Smm_i \times Cfm_i)\right]_p\right] + \sum_{i=1}^{m}(Ter_i \times Smt_i \times Cft_i)}{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n}Smm_i \times Cfm_i\right]_p\right] + \sum_{i=1}^{m}Smt_i \times Cft_i} \quad (Eq.\,1b)$$

Where:

variables with similar names share the descriptions for Equation 1a,

Smm_i = maximum steam generation in units of pounds from unit i that uses CEMS or sorbent trap monitoring,

Cfm_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring,

Smt_i = maximum steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(2) Weighted 30-day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m}Rt_i} \quad (Eq.\,2a)$$

Where:

Her_i = hourly emission rate (*e.g.,* lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}St_i \times Cft_i} \quad (Eq.\,2b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS from the preceding 30-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the ''unit designed for coal ≥ 8,300 Btu/lb'' subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m}Rt_i} \quad (Eq.\,3a)$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}St_i \times Cft_i} \quad (Eq.\,3b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(c) *Separate stack requirements.* For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or

(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified 180 days after April 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum normal operating load of each EGU and the results of the initial performance tests. For this demonstration and prior to submitting your emissions averaging plan, if requested, you must conduct required emissions monitoring for 30 days of boiler operation and any required manual performance testing to calculate an initial weighted average emissions rate in accordance with this section. Should the Administrator require approval, you must submit your proposed emissions averaging plan and supporting data at least 120 days before April 16, 2015. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross electrical output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 day rolling average (90 day rolling average for Hg) basis according to paragraphs (f)(1) through (3) of this section. The first averaging period begins on 30 (or 90 for Hg) days after February 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross electrical output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross electrical output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) *CEMS (or sorbent trap monitoring) use.* If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) *Emissions testing.* If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) *Emissions averaging plan.* You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross electrical output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (*e.g.,* CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO_2, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If the Administrator requests you to submit the plan for review and approval, you must submit a complete implementation plan at least 120 days before April 16, 2015. If the Administrator requests you to submit the plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (h)(1) of this section; and

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in § 63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (*e.g.,* in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

(a) Flue gases from the affected units under this subpart exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under this subpart, the continuous monitoring system installation requirements for these exhaust configurations are as follows:

(1) *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) *Unit(s) utilizing common stack with non-affected unit(s).*

(i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) *Unit with a main stack and a bypass stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack, or, if it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements.

(5) *Unit with a common control device with multiple stack or duct configuration.* If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(6) *Unit with multiple parallel control devices with multiple stacks.* If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(5)(iii)(B) of this section; and

(iv) Divide the result obtained in paragraph (a)(5)(iii)(C) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.,* at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from § 75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f)(1) If you use an SO_2 CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30 boiler operating days.

(4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30-boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30 boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, you must install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.*, period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (*e.g.*, milliamps, PM concentration, raw data signal).

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

(6) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(i) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions are not used in calculations (report any such periods in your annual deviation report);

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods are not used in calculations (report emissions or operating levels and report any such periods in your annual deviation report);

(iii) Any data recorded during periods of startup or shutdown.

(7) You must record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A–3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ± 14°C (320° ± 25°F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh).

(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with § 63.7(f) as an alternative to the performance test method specified in this rule. If approved to use a HAP metals CEMS, the compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for your unit in tables 1 or 2. If approved, you may choose to install, certify, operate, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install and certify your HAP metals CEMS according to the procedures and requirements in you approved site specific test plan as required in § 63.7(e). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

(ii) Operate and maintain your HAP metals CEMS according to the procedures and criteria in your site specific performance evaluation and quality control program plan required in § 63.8(d).

(2) Collect HAP metals CEMS hourly average output data for all boiler operating hours except as indicated in section (j)(4) of this section.

(3) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average HAP metals CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(i) You must use all the data collected during all boiler operating hours in assessing the compliance with your emission limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(ii) You must record and make available upon request results of HAP metals CEMS system performance audits, dates and duration of periods when the HAP metals CEMS is out of control to completion of the corrective actions necessary to return the HAP metals CEMS to operation consistent with your site-specific performance evaluation and quality control program plan.

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in § 63.10000(c)(2)(iii) and Table 7 to this subpart.

§ 63.10011 How do I demonstrate initial compliance with the emissions limits and work practice standards?

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired unit, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with Table 4 to this subpart, § 63.10007, and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.*, tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.*, Hg or HCl) directly, the first 30-boiler operating day rolling average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For a unit that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or filterable PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in § 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to § 63.10030(e).

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, *i.e.*, the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements given in Table 3 for each coal-fired, liquid oil-fired, and solid oil-derived fuel-fired EGU.

Continuous Compliance Requirements

§ 63.10020 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, 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.

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (*e.g.,* flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30-boiler operating day rolling average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n}\ (Eq. 8)$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30 boiler operating days.

(c) If you use a PM CPMS data to measure compliance with an operating limit in Table 4 to this subpart, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (*e.g.,* milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n}\ (Eq. 9)$$

Where:

Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and

(3) Must conduct site-specific monitoring for a liquid oil-fired unit to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020(a).

(e) If you must conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section, perform the first tune-up as part of your initial compliance demonstration. Notwithstanding this requirement, you may delay the first burner inspection until the next scheduled unit outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO_X and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO_X and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_X and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO_X in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups as follows:

(i) If the first required tune-up is performed as part of the initial compliance demonstration, report the date of the tune-up in hard copy (as specified in § 63.10030) and electronically (as specified in § 63.10031). Report the date of each subsequent tune-up electronically (as specified in § 63.10031).

(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with § 63.10031.

(f) You must submit the reports required under § 63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in § 63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under § 63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to § 63.10031.

(h) You must keep records as specified in § 63.10032 during periods of startup and shutdown.

(i) You must provide reports as specified in § 63.10031 concerning activities and periods of startup and shutdown.

§ 63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (3) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test;

(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (*e.g.*, milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (*e.g.*, nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as the highest 1-hour average PM CPMS output value recorded during the performance test. You must verify an existing or establish a new operating limit after each repeated performance test.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (7), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (*e.g.*, use of PM CPMS); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10006(i), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) ''This EGU complies with the requirements in § 63.10021(a) to demonstrate continuous compliance.'' and

(B) ''No secondary materials that are solid waste were combusted in any affected unit.''

§ 63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to § 63.10021(e). Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled unit shutdown.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in § 63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) As of January 1, 2012, and within 60 days after the date of completing each performance test, you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(1) Within 60 days after the date of completing each CEMS (SO_2, PM, HCl, HF, and Hg) performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in § 63.2 and as required in this chapter.

(2) For a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and § 63.10021(f).

(4) Submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under § 63.10030(e) to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1), (2), and (3) of this section in paper format.

(g) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

§ 63.10032 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under § 63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) You must keep records of the occurrence and duration of each startup and/or shutdown.

(g) You must keep records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.

§ 63.10033 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, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(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 § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. 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 under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of ''test method'' in § 63.2.

(3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 63.2 (the General Provisions), and in this section as follows:

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.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14).

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14).

Boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered ''coal'' for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Coal refuse means any by-product 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 with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Cogeneration means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of ''fossil fuel-fired'' or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396–10, ''Standard Specification for Fuel Oils'' (incorporated by reference, see § 63.14).

Dry flue gas desulfurization technology, or *dry FGD,* or *spray dryer absorber* (*SDA*), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO_2 and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (*e.g.*, conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO_2 and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric Steam 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 integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

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

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (*e.g.,* emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO_2 in the exhaust gas stream.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be ''capable of combusting'' fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.*, coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler,* or *CFB* means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the upward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output 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).

Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction or out of control period means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. 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.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

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.

Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se). *Oil* means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (*e.g.,* petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Particulate matter or *PM* means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396–10, ''Standard Specification for Fuel Oils'' (incorporated by reference, see § 63.14).

Responsible official means responsible official as defined in 40 CFR 70.2.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use), or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler.

Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use).

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), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Steam 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 integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14).

Unit designed for coal > 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the ''unit designed for low rank virgin coal'' subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or *wet FGD, or wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO_2 and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

Tables to Subpart UUUUU of Part 63

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	7.0E–3 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GW.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–3 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HC1)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR.		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–4 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	7.0E–3 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–3 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E–2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[4] 9.0E–2 lb/MWh[5]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO^2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	
	Nickel (Ni)	4.1E–0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour
	c. Hydrogen fluoride (HF)	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit ...	a. Filterable particulate matter (PM).	2.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals	OR 6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table . . .
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross electric output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.
[4] Duct burners on syngas; gross electric output.
[5] Duct burners on natural gas; gross electric output

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Individual HAP metals:	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals	OR 6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/MMBtu or 1.8E0 lb/MWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals	OR	Collect a minimum of 1 dscm per run.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits] [1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per Run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	Hydrogen chloride (HCl)	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limits][1]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (*e.g.,* specified sampling volume or test run duration) and limitations with the test methods in Table 5
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–2 lb/TBtu or 6.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Selenium (Se)	1.2E0 lb/TBtu 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[4]	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or Sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.
[2] Gross electric output.
[3] Incorporated by reference, see § 63.14.
[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during startup.	You must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels, either natural gas or distillate oil or a combination of clean fuels for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS—Continued

[As stated in §§ 63.9991, you must comply with the following applicable work practice standards]

If your EGU is . . .	You must meet the following . . .
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use) or at the point of no fuel being fired in the boiler. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler. During shutdown, you must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

TABLE 4 TO SUBPART UUUUU OF PART 63—OPERATING LIMITS FOR EGUS

[As stated in § 63.9991, you must comply with the applicable operating limits]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2] . . .
1. Filterable Particulate matter (PM).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Method 5 at Appendix A–3 to part 60 of this chapter. For positive pressure fabric filters, Method 5D at Appendix A–3 to part 60 of this chapter for filterable PM emissions. Note that the Method 5 front half temperature shall be 160 ° ± 14 °C (320 ° ± 25 °F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR PM CEMS	OR a. Install, certify, operate, and maintain the PM CEMS.	Performance Specification 11 at Appendix B to part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals.	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2] . . .
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration.	Method 29 at Appendix A–8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at Appendix A–8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF).	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations.	Method 26 or Method 26A at Appendix A–8 to part 60 of this chapter or Method 320 at Appendix A to part 63 of this chapter or ASTM 6348–03 [3] with (1) additional quality assurance measures in footnote [4] and (2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR HCl and/or HF CEMS	OR a. Install, certify, operate, and maintain the HCl or HF CEMS.	Appendix B of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A–1 or A–2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A–8 to part 60 of this chapter, ASTM D6784 [3], or Method 29 at Appendix A–8 to part 60 of this chapter; for Method 29, you must report the front half and back half results separately.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

[As stated in § 63.10007, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources [1]]

To conduct a performance test for the following pollutant . . .	Using . . .	You must perform the following activities, as applicable to your input- or output-based emission limit . . .	Using [2] . . .
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR Hg CEMS	
		a. Install, certify, operate, and maintain the CEMS.	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of Appendix A to this subpart.
	OR Sorbent trap monitoring system.	OR a. Install, certify, operate, and maintain the sorbent trap monitoring system.	Sections 3.2.2 and 5.2 of Appendix A to this subpart.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of Appendix A to this subpart.
	OR LEE testing	OR a. Select sampling ports location and the number of traverse points.	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at Appendix A–1 to part 60 of this chapter or Method 30B at Appendix A–8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G, or 2H at Appendix A–1 or A–2 to part 60 of this chapter or flow monitoring system certified per Appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A–1 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981,[3] or diluent gas monitoring systems certified according to Part 75 of this chapter.
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A–3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A–8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.,* per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per Appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 22.0 lb/year threshold.	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS.	Part 75 of this chapter and §§ 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	Part 75 of this chapter and §§ 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A–7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and § 63.10021(h).

[2] See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.
[3] Incorporated by reference, see § 63.14.
[4] When using ASTM D6348–03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (2) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and (4) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x\,100$$

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(g)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

TABLE 7 TO SUBPART UUUUU OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30-boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the arithmetic 30-boiler operating day rolling average of all of the quality assured hourly average PM CPMS output data (*e.g.,* milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring for liquid oil-fired units for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired units to measure compliance with one or more applicable emissions limit in Table 1 or 2.	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

TABLE 8 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS

[As stated in § 63.10031, you must comply with the following requirements for reports]

You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.10031(c)(1) through (4); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e).	Semiannually according to the requirements in § 63.10031(b).

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (h)(2)–(h)(9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c), (d), (e)(2)–(e)(9), (f), (g), and (h).	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1), (c), (d)(1)–(2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii)–(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3), and (d)(3)–(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9).	Reserved	No.

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (*e.g.,* lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, § 63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.,* when the system is ''in control''. However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 *Redundant Backup Systems.* A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on ''hot standby'' in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 *Non-redundant Backup Monitoring Systems.* A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on ''cold standby'' and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 *Temporary Like-kind Replacement Analyzers.* When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix ''LK''.

2.2.4 *Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.* To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (i.e., sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg (Hg^0, CAS Number 7439–97–6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg^{+2} to Hg^0 converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (μg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST–Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards''; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the ''EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators'' or an interim version of that protocol.

3.1.5 *NIST–Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that meets the performance requirements of the ''EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators'' or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (i.e., low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit* or *RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 Quality Assurance *(QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A–1. The CEMS in Figure A–1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

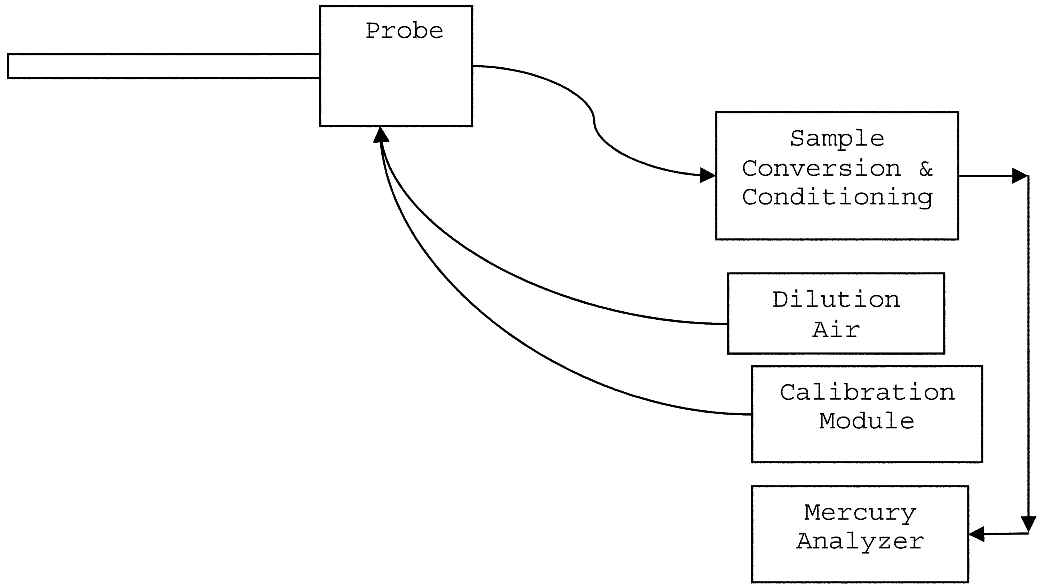

FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg^{+2} to Hg^0 converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 *Sample Probe.* The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A–1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A–1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and $HgCl_2$ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this section) shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (*e.g.,* NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (i.e., a flow monitor, CO_2 or O_2 monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 μg/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 μg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (*i.e.,* the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 μg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 μg/scm; or the next highest multiple of 10 μg/scm.

3.2.1.4.3 *Analyzer Range.* The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Data Collection.* To convert measured hourly Hg concentrations to the units of the applicable emissions standard (*i.e.,* lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§ 63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (*i.e.,* in lb/TBtu), data from a certified CO_2 or O_2 monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (*i.e.,* lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Sorbent Trap Monitoring System Operation.* Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in § 63.10005(g).

4.1.1 *Hg CEMS.* Table A–1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Either elemental or oxidized NIST-traceable Hg standards (as defined in sections 3.1.4 and 3.1.5 of this appendix) may be used for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over nonconsecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.,* resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A–1. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A–1. The LE must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A–1. The SIE must either meet the main performance specification or the alternative specification in Table A–1. (**Note:** This test is not required if the CEMS does not have a converter).

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR Hg CEMS

For this required certification test . . .	The main performance specification[1] is . . .	The alternate performance specification[1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test[2]	$\lvert R - A\rvert \le 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days.	$\lvert R - A\rvert \le 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check[3]	$\lvert R - A_{avg}\rvert \le 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high).	$\lvert R - A_{avg}\rvert \le 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check[4]	$\lvert R - A_{avg}\rvert \le 10.0\%$ of the reference gas concentration at each calibration gas level.	$\lvert R - A_{avg}\rvert \le 0.8$ µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	$\lvert RM_{avg} - C_{avg}\rvert \le 1.0$ µg/scm**	$RM_{avg} < 5.0$ µg/scm.
Cycle time test[2]	15 minutes.[5]		

[1] Note that $\lvert R - A\rvert$ is the absolute value of the difference between the reference gas value and the analyzer reading. $\lvert R - A_{avg}\rvert$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

[2] Use either elemental or oxidized Hg standards; a mid-level or high-level upscale gas may be used. This test is not required for Hg CEMS that use integrated batch sampling; however, those monitors must be capable of recording at least one Hg concentration reading every 15 minutes.

[3] Use elemental Hg standards.

[4] Use oxidized Hg standards. Not required if the CEMS does not have a converter.

[5] Stability criteria—Readings change by <2.0% of span *or* by ≤0.5 µg/scm, for 2 minutes.

** Note that $\lvert RM_{avg} - C_{avg}\rvert$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM_{avg} and C_{avg} can be either + or −.

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784–02 (Reapproved 2008), ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)'' (incorporated by reference, see § 63.14) and Methods 29, 30A, and 30B in appendix A–8 to part 60. When Method 29 or ASTM D6784–02 is used, paired sampling trains are required. To validate a Method 29 or ASTM D6784–02 test run, calculate the relative deviation (RD) using Equation A–1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the average concentration is ≤ 1.0 µg/dscm, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the two Hg concentrations does not exceed 0.2 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{\lvert C_a - C_b\rvert}{C_a + C_b} \times 100 \quad \text{(Eq. A-1)}$$

Where:

RD = Relative deviation between the Hg concentrations of samples ''a'' and ''b'' (percent)

C_a = Hg concentration of Hg sample ''a'' (µg/dscm)

C_b = Hg concentration of Hg sample ''b'' (µg/dscm)

4.1.1.5.1 *Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784–02 (Reapproved 2008), ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)'' (incorporated by reference, see § 63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784–02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in Appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 ''The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 μg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 μg/dscm and >0.5 μg/dscm, ≤ 20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 μg/dscm and >0.1 μg/dscm, ≤ 50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1μg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a μg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry.The main and alternative RATA performance specifications in Table A–1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *Hg CEMS.*

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A–2, below. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use either NIST-traceable elemental Hg standards or NIST-traceable oxidized Hg standards for these calibrations. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for ''non-QA operating quarters''. A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 If required, perform a single-level system integrity check weekly, *i.e.,* once every 7 operating days (see the third column in Table A–2).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.,* once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 *Grace Periods.*

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A–2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 *Conditional Data Validation.* For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	• Use either a mid- or high-level gas. • Use either elemental or oxidized Hg.	$\lvert R - A \rvert \leq 5.0\%$ of span value. *or* $\lvert R - A \rvert \leq 1.0$ μg/scm.

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS—Continued

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Single-level system integrity check	Weekly [1]	• Calibrations are not required when the unit is not in operation. • Required only for systems with converters.	$\lvert R - A_{avg} \rvert \leq$ 10.0% of the reference gas value. *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
Linearity check *or* 3-level system integrity check	Quarterly [3]	• Use oxidized Hg—either mid- or high-level. • Not required if daily calibrations are done with a NIST-traceable source of oxidized Hg. • Required in each "QA operating quarter" [2]—and no less than once every 4 calendar quarters. • 168 operating hour grace period available. • Use elemental Hg for linearity check. • Use oxidized Hg for system integrity check. • For system integrity check, CEMS must have a converter.	$\lvert R - A_{avg} \rvert \leq$ 10.0% of the reference gas value, at each calibration gas level. *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
RATA	Annual [4]	• Test deadline may be extended for "non-QA operating quarters", up to a maximum of 8 quarters from the quarter of the previous test. • 720 operating hour grace period available.	20.0% RA. *or* $\lvert RM_{avg} - C_{avg} \rvert \leq 1.0$ µg/scm, *if* $RM_{avg} < 5.0$ µg/scm.

[1] "Weekly" means once every 7 operating days.
[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.
[3] "Quarterly" means once every QA operating quarter.
[4] "Annual" means once every four QA operating quarters.

5.1.6 *Adjustment of Span.* If you discover that a span adjustment is needed (*e.g.,* if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B–1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, *i.e.,* once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A–4 for Hg CEMS shall apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B–1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§ 63.10010(b) through (d)).

5.4 *QA/QC Program Requirements.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (*e.g.,* changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B–1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (*e.g.,* wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (*e.g.,* one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.,* flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24×10^{-11} to convert it from μg/scm to lb/scf. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average O_2 concentration is above 14.0% O_2 (19.0% for an IGCC) or the hourly average CO_2 concentration is below 5.0% CO_2 (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10^6 to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis. Use Equation 19–19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E_{hj} in Equation 19–19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A–2 of this section (for wet-basis measurements of Hg concentration) or Equation A–3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h \qquad \text{(Equation A-2)}$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/μg-scf,

C_h = Hourly average Hg concentration, wet basis (μg/scm)

Q_h = Stack gas volumetric flow rate for the hour (scfh).

(**Note:** Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h (1 - B_{ws}) \qquad \text{(Equation A-3)}$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/μg-scf.

C_h = Hourly average Hg concentration, dry basis (μg/dscm).

Q_h = Stack gas volumetric flow rate for the hour (scfh)

(**Note:** Use unadjusted flow rate values; bias adjustment is not required).

B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to % H_2O/100)

6.2.2.2 Use Equation A–4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h} x\, 10^3 \qquad \text{(Equation A-4)}$$

Where:

E_{ho} = Electrical output-based Hg emission rate (lb/GWh).

M_h = Hg mass emission rate for the hour, from Equation A–2 or A–3 of this section, as applicable (lb/h).

$(MW)_h$ = Gross electrical load for the hour, in megawatts (MW).

10^3 = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable electrical output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30-boiler operating day rolling average basis. Use Equation A–5 of this section to calculate the Hg emission rate for each averaging period.

$$\overline{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \qquad \text{(Equation A-5)}$$

Where:

$\bar{E}_o$ = Hg emission rate for the averaging period (lb/GWh).

E_{ho} = Electrical output-based hourly Hg emission rate for unit or stack operating hour ‘‘h’’ in the averaging period, from Equation A–4 of this section (lb/GWh).

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters (**Note:** Do *not* include non-operating hours with zero emission rates in the average).

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and any other monitoring system(s) (*i.e.,* flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under § 75.53 (g) of this chapter.

7.1.1.2.1 *Electronic.* The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; Hg monitor span and range information The electronic monitoring plan shall be evaluated and submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

7.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records.* The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (μg/scm, rounded to three significant figures);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to three significant figures). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, *e.g.,* liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A–7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from § 75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

7.1.7 *Records of Diluent Gas (CO_2* or O_2) Concentration.

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO_2 or O_2 concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

7.1.8 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to three significant figures), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A–4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.9 *Certification and Quality Assurance Test Records.* For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;

7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B–1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with § 63.10030.

7.2.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 Submit the electronic and hard copy information in section 7.1.1.2 of this appendix pertaining to the Hg monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also submit the monitoring plan information in § 75.53.(g) pertaining to the flow rate, diluent gas, and moisture monitoring systems within that same time frame, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

7.2.4 *Certification, Recertification, and Quality-Assurance Test Reporting.* Except for daily QA tests of the required monitoring systems (*i.e.,* calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.10.1 through 7.1.10.7 of this section (except for test results previously submitted, *e.g.,* under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.90.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

Appendix B to Subpart UUUUU—-HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with Performance Specification 15 for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems in appendix B to part 60 of this chapter and § 63.10010(a).

2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The provisions of Performance Specification 15 Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 apply.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 The HCl and/or HF CEMS must be certified according to Performance Specification 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below. (**Please Note:** EPA plans to publish a technology neutral performance specification and appropriate on-going quality-assurance requirements for HCl CEMS in the near future along with amendments to this appendix to accommodate their use.)

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (i.e., independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A–8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348–03 (Reapproved 2010) ''Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy'' (incorporated by reference, see § 63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348–03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≥ R ≤ 130%; and

3.1.2.1.4 The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} x\,100 \qquad \text{(Eq. B-1)}$$

3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

5.1 For on-going QA test requirements for HCl and HF CEMS, implement the quality assurance/quality control procedures of Performance Specification 15 of appendix B to part 60 of this chapter as set forth in sections 5.1.1 through 5.1.3 and 5.3.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ± 5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, ''quarterly'' means once every ''QA operating quarter'' (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for ''non-QA operating quarters'' (*i.e.,* calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.3.3.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, ''annual'' means once every four ''QA operating quarters'' (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3 *Data Validation.*

5.3.1 *Out-of-Control Periods.* A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 *Grace Periods.* For the purposes of this appendix, a ''grace period'' is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.4 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.,* 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.2 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for HCl and HF CEMS.*

8.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 *Specific Requirements for HCl and HF CEMS.* The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with § 60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by 9.43×10^{-8} to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is 5.18×10^{-8}.

9.3.2 For electrical output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A–2 or A–3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-8} (for HF) and defining C_h as the hourly average HCl or HF concentration in ppm. Then, use Equation A–4 in appendix A to this subpart to calculate the HCl or HF emission rate in lb/GWh. If the applicable HCl or HF limit is expressed in lb/MWh, divide the result from Equation A–4 by 10^3.

9.4 Use Equation A–5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The term E_{ho} in Equation A–5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (*i.e,* flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 *Contents of the Monitoring Plan.* For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 *Electronic.* Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (*i.e.,* CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 *Operating Parameter Records.* For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.3 *HCl and/or HF Emissions Records.* For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

10.1.4 *Stack Gas Volumetric Flow Rate Records.*

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.,* lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

10.1.5 *Records of Stack Gas Moisture Content.*

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A–7 to part 60 of this chapter.

10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from § 75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

10.1.6 *Records of Diluent Gas (CO_2 or O_2) Concentration.*

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO_2 or O_2 concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

10.1.7 *HCl and HF Emission Rate Records.* For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 *Additional Monitoring Systems.* For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59(a) of this chapter.

11. Reporting Requirements

11.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with § 63.10030.

11.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 Submit the electronic and hard copy information in section 10.1.1.2 of this appendix pertaining to the HCl and/or HF monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also, if applicable, submit monitoring plan information pertaining to any required flow rate, diluent gas, and/or moisture monitoring systems within that same time frame, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*i.e.,* calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in § 75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (*e.g.,* quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (i.e., initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, as specified in Equation 2–4 of Performance Specification 2 in appendix B to part 60 of this chapter;

11.4.3.12 Confidence coefficient, as specified in Equation 2–5 of Performance Specification 2 in appendix B to part 60 of this chapter; and

11.4.3.13 Relative accuracy calculated using Equation 2–6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 *Quarterly Reports.*

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

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